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Pipeline Division

PROCEEDINGS OF THE

AMERICAN SOCIETY OF CIVIL ENGINEERS

BASIC REQUIREMENTS FOR MANUSCRIPTS

Original papers and discussions of current papers should be submitted to the Manager of Technical Publications, ASCE. Authors should indicate the technical division to which the paper is referred. The final date on which a discussion should reach the Society is given as a footnote with each paper. Those who are planning to submit material will expedite the review and publication procedures by complying with the following basic requirements:

1. Titles must have a length not exceeding 50 characters and spaces.

2. A summary of approximately 50 words must accompany the paper, a 300-word synopsis must precede it, and a set of conclusions must end it.

3. The manuscript (an original ribbon copy and two duplicate copies) should be double-spaced on one side of 8½-inch by 11-inch paper. Three copies of all illustrations, tables, etc., must be included.

4. The author's full name, Society membership grade, and footnote reference stating present employment must appear on the first page of the paper.

5. Mathematics are recomposed from the copy that is submitted. Because of this, it is necessary that letters be drawn carefully, and that special symbols be properly identified. The letter symbols used should be defined where they first appear, in the illustrations or in the text, and arranged alphabetically in an Appendix.

6. Tables should be typed (an original ribbon copy and two duplicate copies) on one side of 8½-inch by 11-inch paper. Specific illustrations and explanation must be made in the text for each table.

7. Illustrations must be drawn in black ink on one side of 8½-inch by 11-inch paper. Because illustrations will be reproduced with a width of between 3-inches and 4½-inches, the lettering must be large enough to be legible at this width. Photographs should be submitted as glossy prints. Explanations and descriptions must be made within the text for each illustration.

8. The desirable average length of a paper is about 12,000 words and the absolute maximum is 18,000 words. As an approximation, each full page of typed text, table, or illustration is the equivalent of 300 words.

9. Technical papers intended for publication must be written in the third person.

10. The author should distinguish between a list of "Reading References" and a "Bibliography," which would encompass the subject of his paper.

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Vol. 87, No. PL 2

Journal of the PIPELINE DIVISION

Proceedings of the American Society of Civil Engineers

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September, 1961

Papers

(over)

The three preceding issues of this Journal are dated May 1959, October 1959, and February 1961.

Journal of the

PIPELINE DIVISION

Proceedings of the American Society of Civil Engineers

PIPELINE LOCATION: LOCATION SURVEYS[a]

Progress Report

Task Committee on Pipeline Location

SYNOPSIS

Purpose and generalized procedure of pipeline location surveys are presented, with emphasis on features of detail location and data required for design and special permits. Beginning on approval of the route selected by reconnaissance, the location survey is the pipeline's initial stake-out. The results of the survey are plotted to establish the base map for final design and construction.

INTRODUCTION

Location survey begins on completion of reconnaissance and approval of the selected route. The line usually is delineated on a strip mosaic or a topographic, ownership or county map, that becomes the basic reference for the location survey. Features of preliminary design also are shown to guide field surveying forces.

In preparation for this map it may be necessary to acquire new aerial photographs at a suitably large scale or to enlarge or reduce available maps. In case of enlargement the possible drawbacks, for location purposes, of magnifying scalar errors should be considered.

Note.—Discussion open until February 1, 1962. Separate discussions should be submitted for the individual papers in this symposium. To extend the closing date one month, a written request must be filed with the Executive Secretary, ASCE. This paper is part of the copyrighted Journal of the Pipeline Division, Proceedings of the American Society of Civil Engineers, Vol. 87, No. PL 2, September, 1961.

[a] This paper will form the basis for a chapter in a proposed ASCE Manual of Engineering Practice.

The purpose of a location survey is to mark the route on the ground with refinement, as near to the delineated line as possible.

The techniques of pipeline location surveys are generally similar to those of route surveys for other purposes; hence, they follow general procedures outlined in standard route-surveying texts and manuals. Variations of technique relate to the peculiarities of pipeline design criteria and to other requirements and customs of the pipeline industry.

The pipeline location survey may be performed by a company's forces, or it may be performed by an independent agency, under an engineering service agreement.

Such an agreement, as previously[1] presented, includes most of the field surveying functions required for location and for the preparation of construction drawings, as well as for right-of-way acquisition and as-built drawings. It is, thus, fit for adaptation to most desired scopes of such services.

The basis of compensation is a per diem rate, with specified reimbursements and payments for such normal extras as overtime work, transportation beyond a given distance, and special equipment.

Because the surveying services usually lie within the ASCE definition of engineering,[2] the recommended form should not be used as a basis for seeking competitive bids. Rather it should act as an aid in the process of negotiation of an agreement with a survey engineer who has been selected after due consideration of his qualification to perform the work.

The following material is a general discussion of procedures covered by the agreement form, as they pertain to pipeline location.

Location survey work can begin in the field when permission is obtained for survey crews to stake the centerline and property corners. In establishing the staked line, modifications of the paper location may become necessary. Experienced pipeline location engineers should, therefore, be prepared to look over the ground and select economical and feasible relocations. There may also be a need for right-of-way men, that is, geologists and archaeologists ought to be available during the location survey work.

The surveyed centerline should be marked by stakes every 100 ft or 200 ft, using horizontal or tight-slope chaining and keeping deflection angles to a minimum consistent with code requirements or the structural limitations of the pipe to be used.

Field notes and sketches should be recorded legibly in the field and not copied later.

True bearings should be checked and corrected, by reference to celestial observations or known data such as existing triangulation nets, at the start of work and at least every 12 miles. Compass readings should be recorded at each angle point as a check on the calculated course.

If possible, points of intersection with land lines should be plussed, and the intersection angle of the location line with the land line should be recorded. Fence lines also should be plussed and direction shown. All section corners and property corners should be tied, either by swing ties or intersections, and

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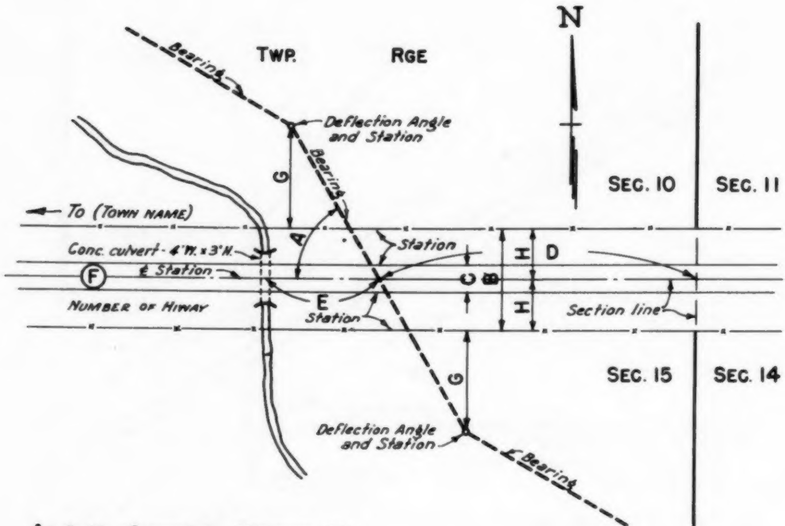
[1] "Pipeline Location: Engineering Service Agreement," Progress Report Task Committee on Pipeline Location, <u>Proceedings</u>, ASCE, Vol. 87, No. PL 1, February, 1961, p. 9.

[2] "Status of Surveying and Mapping in the United States," Task Committee on the Status of Surveying and Mapping in the U. S., <u>Proceedings</u>, ASCE, Vol. 85, No. SU 1, September, 1959.

properly identified. Reference points along the survey should be provided at all intersections, angle points, and at least every 1500 ft on tangent. It is desirable that reference points be identifiable in aerial photographs. Fence lines should be flagged where intersected by the staked line.

Ties also should be made to all easements, roads, highways, railroads, canals, ditches, electric transmission lines, and pipelines. In case of telephone, telegraph or electric power lines, either overhead or underground, they should be properly tied, giving distance of clearance and number of wires. If for pipelines size of pipe or conduit and depth, as well as the owner of the pipe-



A - Angle of crossing - Minimum 60°
B - Width of Right of Way
C - Width of Pavement
D - Tie to Public Survey
E - Tie to Highway structure
F - Kind of pavement or surface
G - Distance Angle point from Right-of-way measured at right angles
H - Distance ℄ pavement to Right-of-way
Furnish profile of line between points 100 feet from right-of-way line

Furnish General Location Map

When "B" Is	Make "G"
50 Ft. to 60 Ft.	100 Ft.
70 " " 80 "	90 "
90 " " 100 "	80 "
100 " " 120 "	70 "
140 " " 160 "	60 "
180 " " 200 "	50 "
200 " " 300 "	50 "
Over 300 Ft.	50 "

FIG. 1.—TYPICAL LAYOUT OF HIGHWAY CROSSING

line, are recorded, then their stations or mileposts should be equated to the new survey.

Railroads and highways should be approached as nearly as possible to right angles.

Where skew crossings are necessary they should be located for maximum economy, taking into account the pipelines bending, the hydraulic require-

ments, excavation, encasement costs and any other pertinent factors. The acute angle between the line and the installation crossed is rarely smaller than 30°.

Field data taken at rail and highway crossing should include a profile of the ground at the proposed crossing, showing grade of the traveled way as well as depth of pipeline. Other data should include ties to stationing and structures, type of construction and use (primary, secondary, main line-siding), number

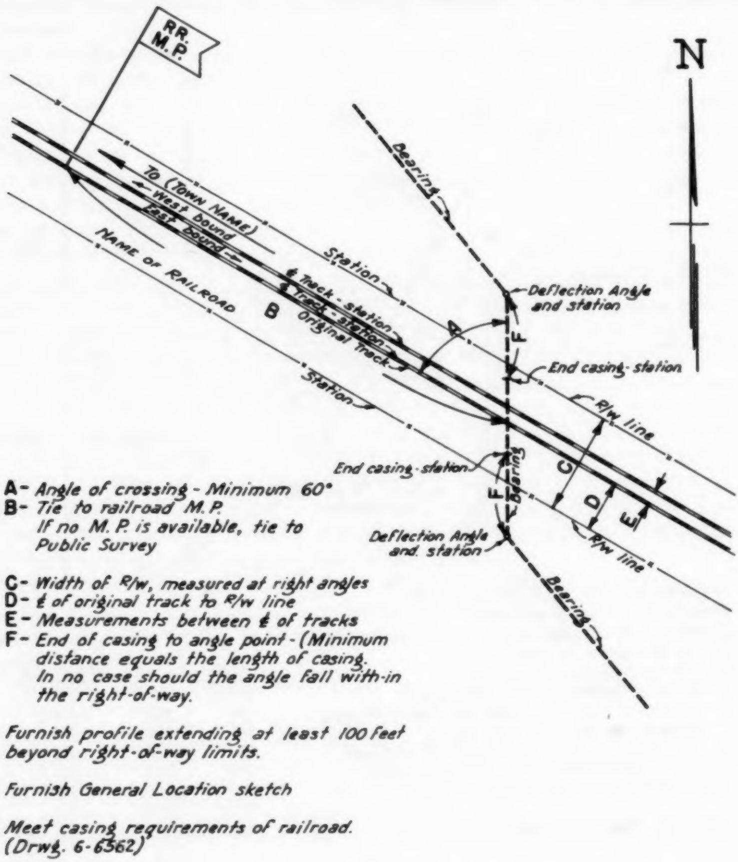


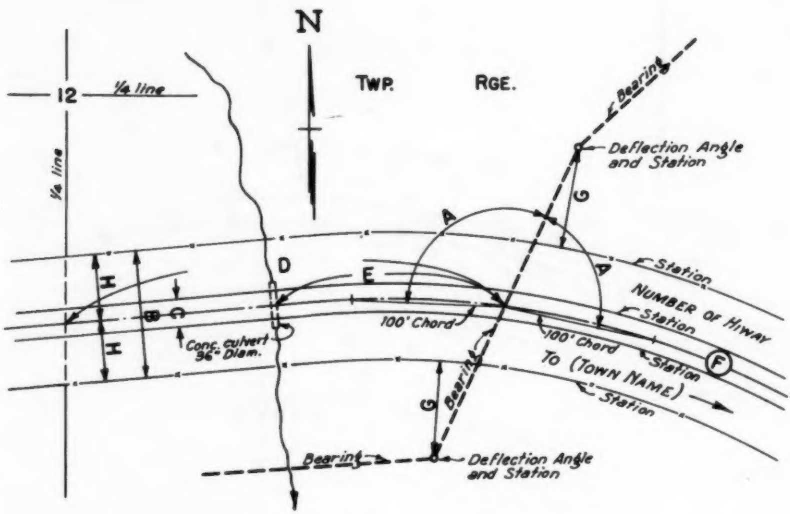
FIG. 2.—TYPICAL LAYOUT OF RAILROAD CROSSING

of lanes or tracks, and other data that would aid designers. Typical layouts and examples of highway and railroad crossings are give in Figs. 1 through 6.

High fills and deep cuts should be avoided. In this connection state and local highway departments should be contacted to determine future improvements plans that would affect location.

Locations across railroads and highways, as well as those across other pipelines and streams, should avoid rock that would have to be blasted. It should be noted further whether the material is borable by jacking or other techniques, and any site drainage problems should be foreseen.

River crossings require particularly careful design and, hence, extra effort during the pipeline location survey. The object is to obtain a crossing that will stay put, enduring scour, undue silting, and damage from debris, anchors, vessels and other marine hazards.



A- *Angle of crossing - Minimum 60°*
B- *Width of Right-of-Way*
C- *Width of Pavement*
D- *Tie to Public Survey*
E- *Tie to Highway Structure*
F- *Kind of Pavement or Surface*
G- *Distance angle point from Right-of-Way measured at right angles*
H- *Distance ℄ pavement to Right-of-way*
Furnish profile of line between points 100 feet from right-of-way line

Furnish General Location map

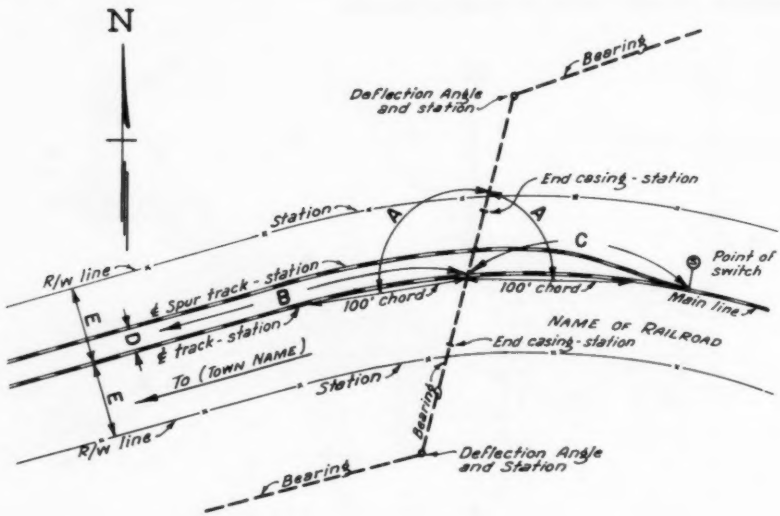
WHEN "B" IS	MAKE "G"
50 Ft. to 60 Ft.	100 Ft.
70 " " 80 "	90 "
90 " " 100 "	80 "
100 " " 120 "	70 "
140 " " 160 "	60 "
180 " " 200 "	50 "
200 " " 300 "	50 "
Over 300 Ft.	50 "

FIG. 3.—TYPICAL LAYOUT OF HIGHWAY CROSSING ON A CURVE

It should be determined whether the stream is navigable or not. If navigable, or if there are other conditions of use or jurisdiction requiring official permits, the physical-data requirements for the permits should be learned in advance and fulfilled during the location survey.

Engineering data required at significant stream crossings should start with a complete topographic survey of bank areas for a distance upstream and

downstream sufficient to determine the detailed location and to justify the selected location. Bottom hydrography, too, should be obtained, together with information on soil types, rock outcrops, evidence of high water, other hydrologic factors, and availability of construction materials for bedding, riprapping, and other pipe protection. A more detailed examination of this subject, including United States Corps of Engineers requirements, is forthcoming.



A - Angles between survey line and 100 foot chords - (Smaller angle, minimum 60°)
B - Tie to railroad mile post, public survey, permanent railroad structure
C - Tie to switch point
D - Distance between tracks
E - Center line of main track to right-of-way line

Furnish profile of line between points 100 feet beyond right-of-way line

Furnish General Location sketch

Meet casing requirements of railroad (Drwg. 6-6562)

FIG. 4.—TYPICAL LAYOUT OF RAILROAD CROSSING ON A CURVE

Mining claims should be indicated, as for other types of property. In the case of lode claims the survey should be tied to discovery shafts and the corners. Placer-claim corners should be tied to the survey. Any information found at the claim, such as posted notices and maps, should be recorded.

Other land lines that should be identified and tied in include the boundaries of political units, Indian reservations, and preserves such as state and national

forests, parks, and wildlife refuges. Where applicable, all necessary data for permits should be obtained.

Notes should show classifications of the country through which the line runs—as to type of land use, both existing and potential, and type of surface, and subsurface, and rock.

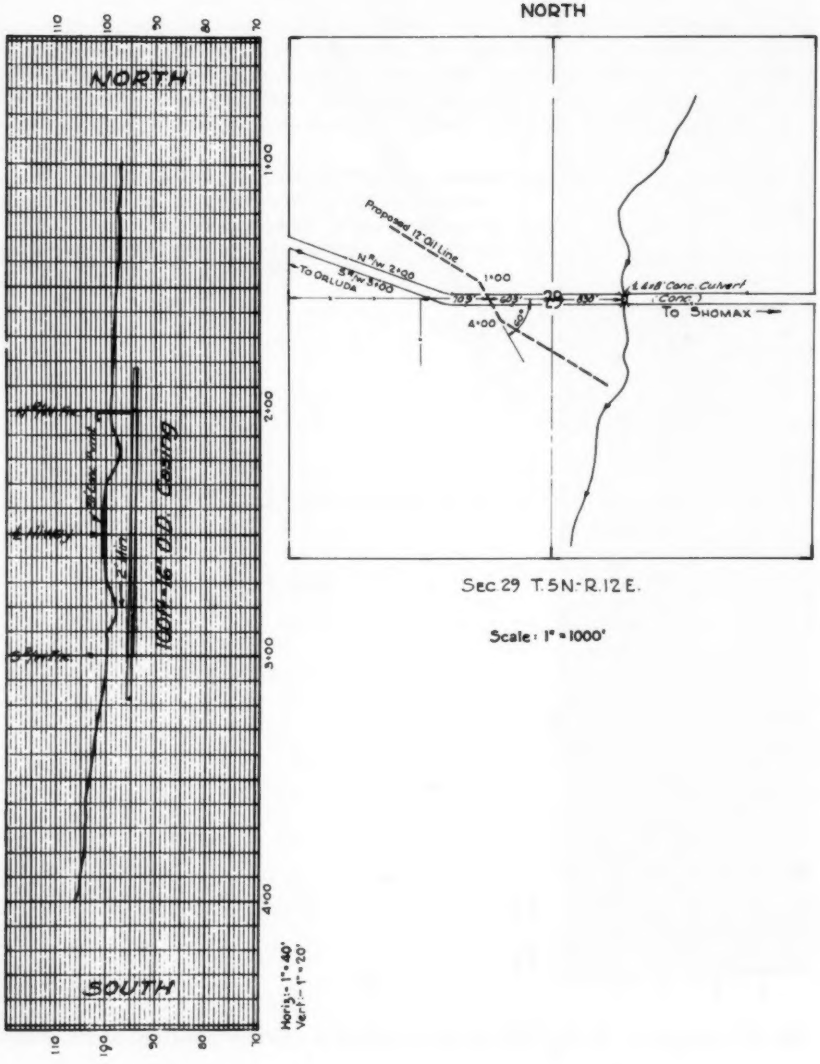


FIG. 5.—EXAMPLE OF METHOD USED TO SHOW A TYPICAL HIGHWAY CROSSING

All topographical features and other pertinent information that could affect ultimate design should be noted and tied in regardless of the distance from the centerline. It is far better to have too much information than not enough. For

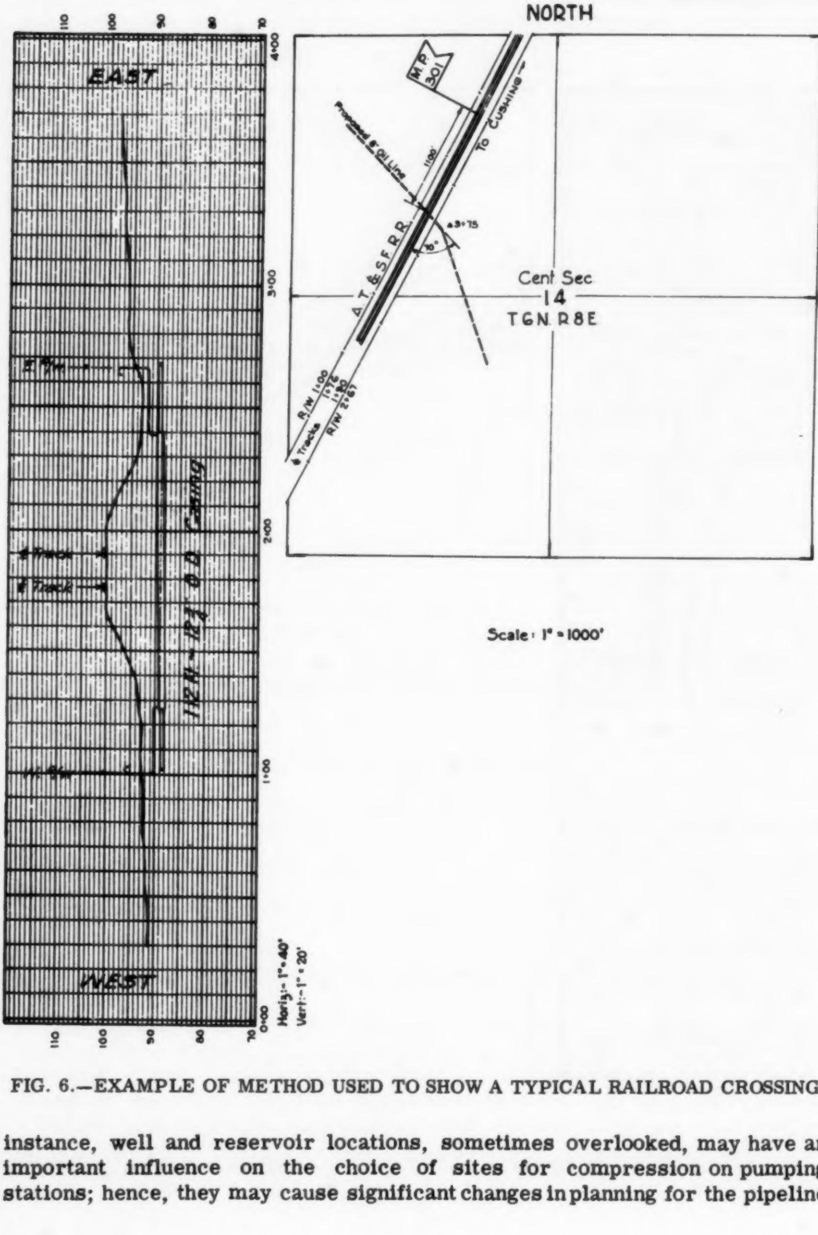


FIG. 6.—EXAMPLE OF METHOD USED TO SHOW A TYPICAL RAILROAD CROSSING

instance, well and reservoir locations, sometimes overlooked, may have an important influence on the choice of sites for compression on pumping stations; hence, they may cause significant changes in planning for the pipeline

location. Factors in station site location will be described subsequently.

A reasonable distance should be kept from schools, churches, public buildings, factories, dwellings, and other places of occupancy, so as to conform with good pipelining practice and to applicable codes.

In areas in which historic dwellings, ruins, or fossilferous objects may be found, the proposed location should be shown to agencies having cognizance of such treasures. These agencies, including forest and park departments, conservation agencies, and major museums, can advise on areas to be avoided or to be investigated by archaeologists. The investigations probably should be conducted ahead of the location survey work to permit restudy of the line in the event of conflicts. Thus, the paper location could be changed in time to avoid expensive line changes and the possible need for additional right of way purchase.

The results of the location survey are plotted to establish the base map for final design and for construction of the pipeline.

This report is respectfully submitted by the Task Committee on Pipeline Location, Committee on Pipeline Location of the Pipeline Division.

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Journal of the
PIPELINE DIVISION
Proceedings of the American Society of Civil Engineers

RELATIONSHIP OF COMPRESSION RATIO TO GAS PIPELINES

By Raymond R. Crawford,[1] M. ASCE

SYNOPSIS

One phase of gas pipeline engineering that deserves more detailed study, particularly in light of modern technical achievement made in operating equipment in control systems, is the application of the concept of low line compression ratio in conjunction with high mean effective line pressure to the design and operation of gas transmission pipeline systems. The use of this concept in the design of such a system may result in greater pipeline efficiency and significant dollar savings both in capital and operating costs.

This concept as well as examples of economic benefits that may be attained through its application are described. Also included is a general review of the relationship between line compression ratio and the various analytical factors involved in pipeline gas flow, and comparative studies of the effect of line compression ratio and mean effective pressure on the economic factors of capital and operating costs for gas pipelines.

INTRODUCTION

With the advent of high yield strength line pipe of the API-5LX type, particularly with the X-52 and X-56 grades and the impending (1961) advent of X-60 grade line pipe, the working pressure of gas transmission pipelines has increased to more fully utilize the benefits of this high strength pipe. To capitalize on the advantages of high strength line pipe, design practice appears to

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[1] Cons. Engr., San Rafael, Calif.

favor the philosophy of spacing compressor stations as far apart as possible in order to minimize the number of stations and, thus, lower station capital and operating costs for any given gas transmission pipeline system. This may achieve economy in station operations but the potential capacity of the pipe in the system will not be realized. This is so under the condition of far-apart station spacing because the pipe in a constant wall thickness pipeline may be pressured to code design pressure only during such times as the line is in a packed condition; and in a tapered wall thickness pipeline under line pack conditions some of the pipe may never be pressured to code design pressure. During normal operating flow conditions, considerable portions of the pipe in either of the previously noted types of line will be working at pressures lower than the allowable working pressure as determined by code design.

The physical properties of high yield strength line pipe may be utilized more fully by increasing the mean effective line pressure. This may be accomplished by either raising the line design pressure as shown in Fig. 1, or by

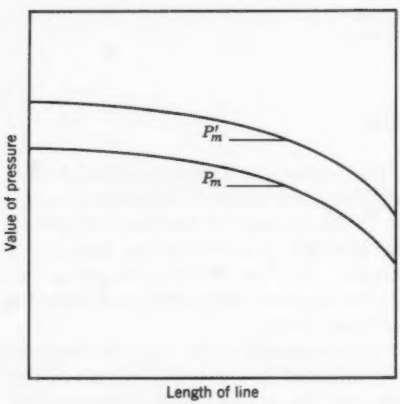

FIG. 1.—INCREASING P_m BY RAISING P

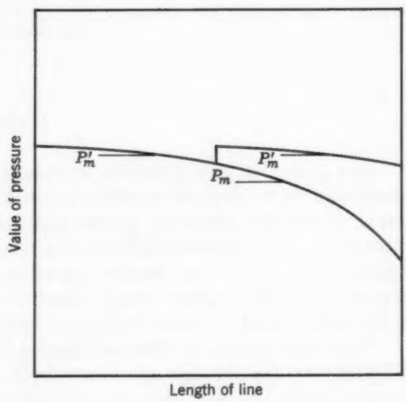

FIG. 2.—INCREASING P_m BY LOWERING r

lowering the line compression ratio, with design pressure of the line remaining constant, as shown in Fig. 2.

The writer intends to explore the compression ratio side of the concept with respect to its application to gas pipeline systems.

The mathematical reductions of various equations are not intended to be rigorous solutions, but rather, informal expressions of these equations in a simple form for clarity of analysis.

It is recognized that pressure drop in a gas pipeline under flow conditions is a state of decompression; however, for reasons of convenience, line compression ratio will be considered as the compression necessary to counteract the line pressure drop, or decompression, in a flowing gas pipeline.

Low compression ratio, by definition herein, are considered in the range of 1.04 to 1.15 and high mean effective line pressures are considered in the range of 1200 psia and greater. For convenience all discussion of fluid flow will be limited to a level pipeline and to the compression ratio of the pipeline between

compressor stations; thus eliminating the complexity of elevation corrections and the variability of compressor station pressure losses.

Notation.—The letter symbols adopted for use in this paper are defined where they first appear, in the illustrations or in the text, and are arranged alphabetically, for convenience of reference, in the Appendix.

RELATIONSHIP OF LINE COMPRESSION RATIO AND GAS FLOW FACTORS

The mechanics of pressure drop in a gas pipeline under flow conditions are a complex of interacting and counteracting forces and conditions that act on the flowing gas. Briefly stated these mechanics consist of pressure energy being expended to overcome friction resistance to the gas flow; this pressure loss in turn permits expansion of the gas, with a corresponding increase in velocity and mean effective compressibility of the flowing gas. Increase of the mean effective compressibility factor causes further expansion of the gas and increase in the velocity of the gas flow. These changes cause further increase

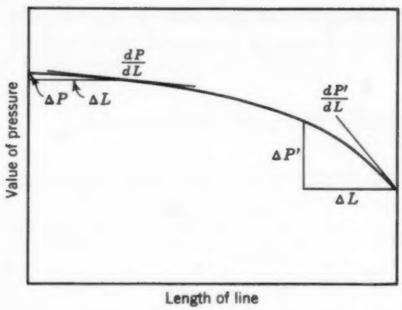

FIG. 3.—TYPICAL FLOW PRESSURE GRADIENT

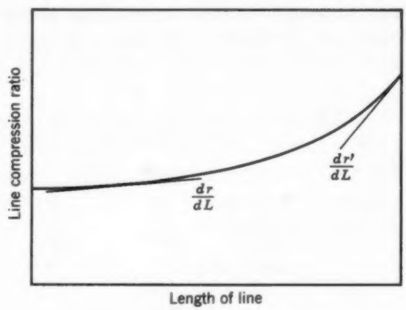

FIG. 4.—TYPICAL r GRADIENT

in line pressure drop. This basic cycle is repetitive for each increment of pipeline length in the direction of the gas flow.

A typical flow pressure gradient for a gas pipeline, as defined by the gas flow equation and as shown in Fig. 3, is a curve with the characteristic of rate of pressure drop $\frac{dp}{dL}$ increasing with pipeline length L. Thus the pressure drop Δp per unit length of line ΔL correspondingly increases with increasing line length. Accordingly, from Fig. 3 it is seen that

$$\frac{\Delta p}{\Delta L} < \frac{\Delta p'}{\Delta L}$$

and

$$\underset{\Delta L \to 0}{\text{Limit}} \frac{\Delta p}{\Delta L} = \frac{dp}{dL}$$

thus

$$\frac{dp}{dL} < \frac{dp'}{dL}$$

and by deduction from the preceding relations it would appear that a reduction in pipeline pressure drop, at flowing conditions, for any given system could be effected by operating the line in the high pressure region of the flow pressure gradient.

Pipeline compression ratio r is defined as the ratio of pipeline inlet pressure P_1 to pipeline outlet pressure P_2 $\left(r = P_1/P_2\right)$, wherein the pressures are in pounds per square inch absolute. Line compression ratio is, thus, a function of pipeline pressures. A typical line compression ratio curve for constant line flow rate and inlet pressure conditions is shown in Fig. 4 and as indicated the rate of change in line compression ratio increases with respect to increasing lenght, or $\frac{dr}{dL} < \frac{dr'}{dL}$.

From the preceding analysis it is evident the line pressure drop per incremental length of line is greatest at the outlet end of the line and is least at the inlet end of the line. Because pressure drop is energy loss and this loss of energy must be restored by recompression of the gas in the line to maintain gas flow conditions it would appear that to arrive at minimum system power requirements for recompression of the gas at constant line flow it would be possible to minimize pressure drop in the line by lowering the line compression ratio. To illustrate the above argument assume a 30 in. diameter pipeline 100 miles long flowing at the rate of 600,000,000 standard cubic feet of gas per day (MMCFD) with a line inlet pressure of 1,000 psia. Ignoring the effect of the gas compressibility factor and station pressure losses, the total pressure drop for the line as calculated from the assumed data and for various line compression ratio is as shown in Table 1.

TABLE 1.—RELATIONSHIP OF COMPRESSION RATIO STATION SPACING AND PRESSURE DROP

Length L, in miles (1)	Pipeline compression ratio, r (2)	P_1 psia (3)	P_2 psia (4)	ΔP psi (5)	Number of Stations (6)	$\Sigma\Delta P$ psi (7)	P_m psia (8)
100	1.67	1000	597	403	1	403	817
50	1.22	1000	824	176	2	352	917
25	1.09	1000	916	84	4	336	961

Table 1 indicates a considerable decrease in overall system pressure drop $\Sigma\Delta P$ as line compression ratio is decreased. This lowering of system pressure drop points to savings that might be effected in pipeline operating power requirements for low line compression ratio systems.

The flow equation as appears in the work of R. V. Smith, J. S. Miller and J. W. Ferguson[2] has been selected for convenience only and will be used to further explore the relationship of compression ratio and the various analytical components of the gas flow equation. This equation is

$$Q = K \frac{T_o}{P_o} \left[\frac{\left(P_1^2 - P_2^2\right) d^5}{G\ T\ L\ f\ Z} \right]^{1/2} \qquad \text{.............(1)}$$

in which Q is the rate of flow of gas in cubic feet per hour at a standard pressure base, P_o in pounds per square inch absolute, and at a temperature base T_o in degrees Fahrenheit absolute temperature(F°plus 460); P_1 denotes the line inlet pressure in pounds per square inch absolute, and P_2 is line outlet pressure in pounds per square inch absolute; d represents internal diameter of the pipe in inches; G denotes the specific gravity of the gas in the line on the basis of air equals 1.00; T refers to the temperature of the flowing gas in degrees Fahrenheit absolute; L is the length of the pipeline in miles; f represents the dimensionless resistance coefficient; Z is the dimensionless average compressibility factor for the gas at flowing conditions; and K represents the numerical constant 1.6158.

By rearranging, elimination of the square root sign, and substitution of the constant

$$C = \left(\frac{P_o^2}{K^2\ T_o^2} \right) \left(\frac{G\ T\ f}{d^5} \right) \qquad \text{................(2)}$$

the gas flow equation is reduced to

$$P_1^2 - P_2^2 - C\ Q^2\ L\ Z \qquad \text{...............(3)}$$

Elimination of P_2 by substitution of the compression ratio yields

$$P_1^2 \left(1 - \frac{1}{r^2}\right) = C\ Q^2\ L\ Z \qquad \text{...............(4)}$$

RELATIONSHIP OF COMPRESSION RATIO AND LINE FLOW RATE

To demonstrate the effect of line compression ratio on the flow rate of gas in a pipeline the basic flow equation is rearranged to read

$$Q = P_1 \left(1 - \frac{1}{r^2}\right)^{1/2} \left(\frac{1}{C\ L\ Z} \right)^{1/2} \qquad \text{...........(5)}$$

and assuming Q and r as variables and all other factors constant then

$$C' = P_1 \left(\frac{1}{C\ L\ Z} \right)^{1/2} \qquad \text{.................(6)}$$

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[2] "Flow of Natural Gas through Experimental Pipelines and Transmission Lines," by R. V. Smith, J. S. Miller, and J. W. Ferguson, Monograph No. 9, Bur. of Mines, U. S. Dept. of Interior, Washington, D. C., 1956.

and

$$Q = C_1 \left(1 - \frac{1}{r^2}\right)^{1/2} \qquad (7)$$

is shown as $\frac{Q}{C_1}$ versus r in Fig. 5.

It is apparent by inspection of Fig. 5 that as line compression ratio approaches 1.00 $\frac{Q}{C_1}$ rapidly approaches zero, and as the compression ratio approaches infinity then $\frac{Q}{C_1}$ slowly approaches 1.00. It is observed that the rate of change in values of $\frac{Q}{C_1}$ is greatest in the range of low compression ratio. Thus it is noted that increasing the line compression ratio to attain greater flow will result in a rapidly diminishing rate of change in $\frac{Q}{C_1}$ in the region of r

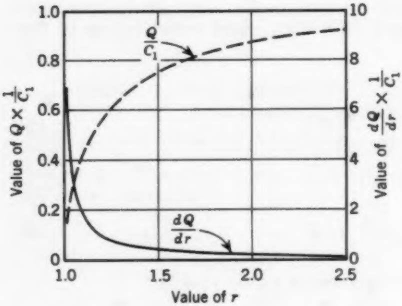

FIG. 5.—EFFECT OF r ON Q

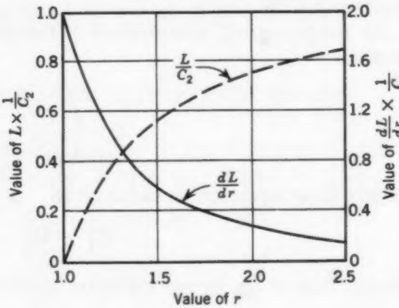

FIG. 6.—EFFECT OF r ON L

less than 2, and in the region of r greater than 2 the rate of change in $\frac{Q}{C_1}$ values slowly decreases. Thus large increases in compression ratio in the region of r greater than 2 will result in diminishing small increases in line flow rate.

The range of compression ratio wherein the greatest rates of change in $\frac{Q}{C_1}$ values occur may be better defined by investigating the slope of the $\frac{Q}{C_1}$ curve by use of the derivative

$$\frac{dQ}{dr} = \frac{C_1}{r^3\left(1 - \frac{1}{r^2}\right)^{1/2}} = \frac{C_1}{r^2\left(r^2 - 1\right)^{1/2}} \qquad (8)$$

The curve representing this derivative is also shown in Fig. 4. The curve of the derivative is seen to break sharply in the area of r equals 1.20, and it

is evident that the slope of $\frac{Q}{C_1}$ curve changes rapidly with respect to decreasing compression ratio in the region of the curve in which r is less than 1.20. In the region of r greater than 1.20 the slope of the $\frac{Q}{C_1}$ curve changes very slowly with respect to increasing compression ratio; thus it is evident that increasing compression ratio to gain greater line flow will result in a rapid approach to a point of diminishing return in a region of compression ratio above 1.20.

RELATIONSHIP OF COMPRESSION RATIO AND LINE LENGTH

The effect of compression ratio on length of pipeline between recompression points is shown, referring to the basic flow formula, by letting

$$C_2 = \frac{P_1^2}{C\ Q^2\ Z} \quad \text{. (9)}$$

then by substitution and rearranging the basic equation is in the form of

$$L = C_2\left(1 - \frac{1}{r^2}\right) \quad \text{. . . . . (10)}$$

This equation is shown as the relation $\frac{L}{C'}$ versus r in Fig. 6.

The $\frac{L}{C_2}$ curve is similar in shape to the $\frac{Q}{C'_1}$ curve shown in Fig. 5. As the compression ratio approaches infinity, $\frac{L}{C_2}$ values slowly approach 1.0; and as the compression ratio approaches 1.0, the $\frac{L}{C_2}$ values rapidly approach zero. Thus it is seen that large increases of compression ratio in the region of the curve above r values of 2.0 result in diminishing changes in $\frac{L}{C_2}$ values.

The rate of change in $\frac{L}{C_2}$ values is not too evident in Fig. 6. Further investigation of the slope of the $\frac{L}{C_2}$ curve by means of the derivative

$$\frac{dL}{dr} = C_2\ \frac{2}{r^3} \quad \text{. (11)}$$

still does not indicate any sharp change in the slope of the $\frac{L}{C_2}$ curve. However, inspection of the $\frac{dL}{dr}$ curve shows the greater rates of change in $\frac{L}{C_2}$ values occur at compression ratio values below 1.5, and at compression ratio values for which r is greater than 2 the rate of change in $\frac{L}{C_2}$ values with respect to compression ratio is small and relatively uniform; thus, it is evident that increasing compression ratio to gain greater line length between recompression

points results in a rapid approach to a point of diminishing return at compression ratio above 1.5.

RELATIONSHIP OF COMPRESSION RATIO AND MEAN EFFECTIVE LINE PRESSURE

The effect of compression ratio on mean effective line pressure is illustrated by use of the equation

$$P_m = \frac{2}{3}\left[(P_1 + P_2) - \frac{P_1 P_2}{P_1 + P_2}\right] \qquad (12)$$

in which P_m represents mean effective line pressure in pounds per square inch absolute and all other nomenclature as previously noted. By equating P_2 in terms of P_1 and r

$$P_2 = \frac{P_1}{r} \qquad (13)$$

Substituting yields

$$P_m = \frac{2}{3} P_1 \left[\frac{r + 1}{r} - \frac{1}{r + 1}\right] \qquad (14)$$

and by letting

$$C_3 = \frac{2}{3} P_1 \qquad (15)$$

then

$$P_m = C_3\left[\frac{r + 1}{r} - \frac{1}{r + 1}\right] \qquad (16)$$

This last equation is shown as $\frac{P_m}{C_3}$ versus r in Fig. 7.

Inspection of Fig. 7 shows the rate of change in $\frac{P_m}{C}$ values with respect to r is numerically greater at low values of compression ratio, and diminishes uniformly to approach a $\frac{P_m}{C_3}$ value of 1.0 as r approaches infinity. Further investigation of the slope of the $\frac{P_m}{C_3}$ curve by use of the derivative

$$\frac{dP_m}{dr} = -C_3\left[\frac{2r + 1}{(r^2 + r)}\right] \qquad (17)$$

also shown in Fig. 7, shows no more than the $\frac{P_m}{C}$ versus r curve. However, these curves indicate numerically greater rates of change in $\frac{P_m}{C_3}$ values with respect to r occur at compression ratio values below 1.6. At compression ratio values above 2.0 the rate of change is small and approaches zero slowly. Thus large increases in compression ratio at values above 2.0 result in diminishing small

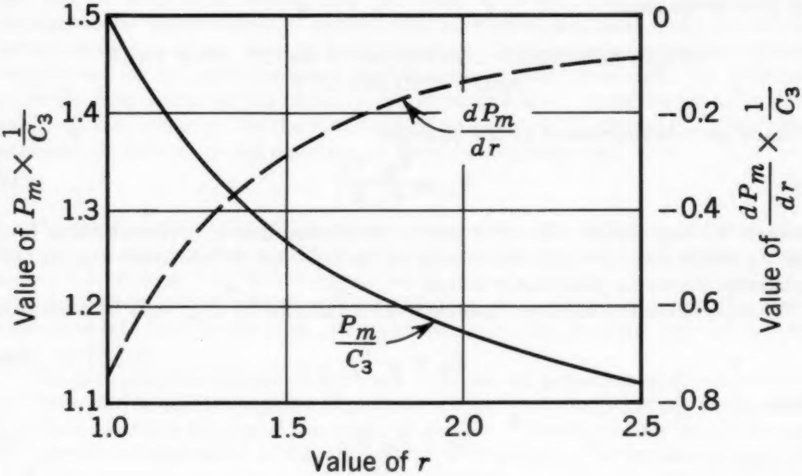

FIG. 7.—EFFECT OF r ON P_m

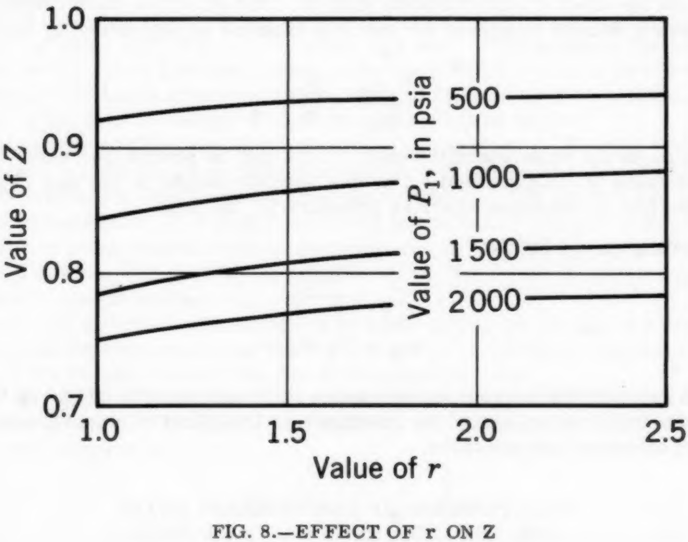

FIG. 8.—EFFECT OF r ON Z

changes in $\frac{P_m}{C_3}$ values with respect to r, and as a corollary low line compression ratio result in high mean effective line pressures and better utilization of the pipe in the line.

RELATIONSHIP OF COMPRESSION RATIO, LINE PACK AND FLUID DENSITY

Line pack is expressed by the equation

$$V_1 = \frac{P_m\ V_2}{P_o\ Z} \quad \text{.................. (18)}$$

wherein V_1 represents volume of gas in the packed line in standard cubic feet, and V_2 designates the internal volume of the pipeline in cubic feet and all other nomenclature as previously noted.

This equation establishes line pack as a function of P_m, and by assuming

$$C_4 = \frac{V_2}{P_o\ Z} \quad \text{.................. (19)}$$

then

$$V_1 = C_4\ P_m \quad \text{.................. (20)}$$

and by substituting for P_m in terms of r then

$$V_1 = C_3\ C_4 \left[\frac{r+1}{r} - \frac{1}{r+1}\right] \quad \text{.............. (21)}$$

Thus, the effect of compression ratio on line pack is the same, except for constants, as the effect of compression ratio on mean effective line pressure.

Pressure density relations for gas in a pipeline is expressed by the equation

$$\frac{Z\ \rho_m}{\rho_o} = \frac{P_m}{P_o} \quad \text{.................. (22)}$$

wherein ρ_o is the base specific weight of the gas in pounds per cubic foot at base pressure P_o in psia; and ρ_m is the specific weight of the gas in pounds per cubic foot at the mean effective pressure P_m in psia.

By rearranging and letting

$$C_5 = \frac{\rho_o}{P_o\ Z} \quad \text{.................. (23a)}$$

then

$$\rho_m = C_5\ P_m \quad \text{.................. (23b)}$$

then the relationship between compression ratio and specific weight of the gas in the line is the same, except for constants, as the effect of compression ratio on mean effective line pressure.

RELATIONSHIP OF COMPRESSION RATIO AND GAS COMPRESSIBILITY FACTOR

The characteristic equation of state for an ideal gas is

$$p\ v = R\ T \quad \text{.................. (24)}$$

in which p denotes pressure, v is the specific volume, R refers to the gas constant and T the absolute thermodynamic temperature, all in consistent units. It has been shown that this ideal gas law is not entirely valid for any actual gas and that the state of an actual gas, particularly in the range of pressures and temperatures encountered in modern gas pipelines, deviates from that as determined by use of the ideal gas relationship. For instance more gas (pounds weight) can be compressed into a unit volume at high pressure, say 1000 psia at 60°F, than would be indicated by the ideal gas law. This deviation is compensated for, usually, by the inclusion of an empirical constant, called compressibility factor, in the equation of state for an ideal gas, thus

$$p\,v = Z\,R\,T. \qquad (25)$$

The mathematical definition of gas compressibility factor in terms of compression ratio involves a complex approach through the application of some one of the various theoretical equations of state for a gas. To avoid the use of such equations, published values[3] for the gas compressibility factor have been used to relate this factor with compression ratio for various line inlet pressure conditions.

The gas compressibility factor is a function of pressure and temperature and becomes a direct function of pressure only when temperature is constant. It is thus possible to relate the mean effective compressibility factor for gas at constant temperature to mean effective line pressure in terms of line inlet pressure and compression ratio. This relation is shown in Fig. 8 wherein compressibility factor is plotted against compression ratio for constant gas temperature and specific gravity conditions and for several conditions of constant line inlet pressure.

These Z versus r curves show that the greater rates of change in Z values with respect to r occur at compression ratio values below 1.25. The lower values of compressibility factor gained by decreasing compression ratio result in a greater flow rate for any given line size. Flattening of the compressibility factor curve for inlet pressure constant at 2000 psia is attributed to Z values approaching a minimum in the range of 2000 psia which results in a decrease in the rate of change of compressibility factor values.

Relationship of Compression Ratio and Temperature of Flowing Gas.—Line compression ratio has been defined herein as the recompression of gas necessary to counteract line pressure drop under constant flow conditions. Because heat of compression is a major source of temperature change in flowing gas, the effect of compression ratio on the temperature of flowing gas, excluding the Joules-Thomson effect, will be considered on the basis of gas temperature rise due to compression.

Using this approach and assuming no aftercooling of the gas in a compressor station, the temperature of the flowing gas at compressor discharge can be taken as the temperature of the gas at the pipeline inlet.

The effect of compression ratio on the temperature of flowing gas at pipeline inlet is defined by use of the equation for temperature rise of gas for isentropic compression

$$T_2 = T_1 \left(r^{\frac{k-1}{k}} \right) \qquad (26)$$

3 "Simplified Compressibility Factor Charts for Natural Gas Calculations," by Carl Gatlin, Univ. of Tulsa, Tulsa, Okla.

in which T_2 is taken as pipeline inlet temperature and T_1 as pipeline outlet temperature both in degrees Fahrenheit absolute, and k is the ratio of specific heats of the gas taken at 1.27.

Let $T_1 = C_6$ then

$$T_2 = C_6\left(r^{\frac{k-1}{k}}\right) \qquad (27)$$

This equation is shown as the relation of $\frac{T_2}{C_6}$ versus r in Fig. 9. Inspection of this curve shows the effect of compression ratio on line inlet temperature is fairly uniform, and the rate of change in $\frac{T_2}{C_6}$ values with respect to r is not too evident. Hence, it is necessary to further investigate the slope of the $\frac{T_2}{C_6}$ curve as defined by the derivative

$$\frac{d\,T_2}{dr} = C_6\ C_7\left(\frac{1}{r^{1/k}}\right) \qquad (28)$$

in which

$$C_7 = \frac{k-1}{k} \qquad (29)$$

The curve representing this derivative is also shown in Fig. 9, and again by inspection greater rates of change in $\frac{T_2}{C_6}$ values with respect to r occur at compression ratio values less than 1.5; thus, low compression ratios have a greater effect on line inlet temperature than do high compression ratios.

Consideration of the relationship of $\frac{T_2}{C_6}$ values versus r values, only, indicates that higher line compression ratio would result in lower overall line temperature input into the flowing gas. However, total input of temperature into the flowing gas is a product of the number of compression points in a pipeline, which in turn is a function of station spacing or line length as defined herein. Fig. 6, which shows the effect of compression ratio on line length, indicates that the rate of change in line length with respect to compression ratio is very small as compression ratio increases in the high range, and ultimately approaches zero as compression ratio approaches infinity. On the other hand, in Fig. 9 the rate of change in gas inlet temperature with respect to compression ratio is relatively uniform in the high range of compression ratio. Considering the effect of compression ratio on line length or station spacing, in conjunction with the effect of compression ratio on line inlet temperature, it is seen that increases of compression ratio in the higher ranges result in small increases in station spacing and proportionally greater increases in the inlet temperature of the gas. Thus it is seen the total temperature input into

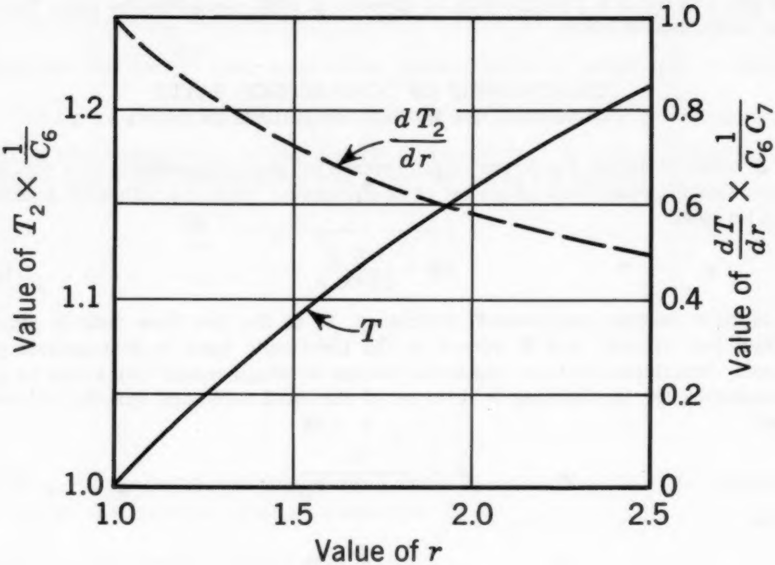

FIG. 9.—EFFECT OF r ON T_2

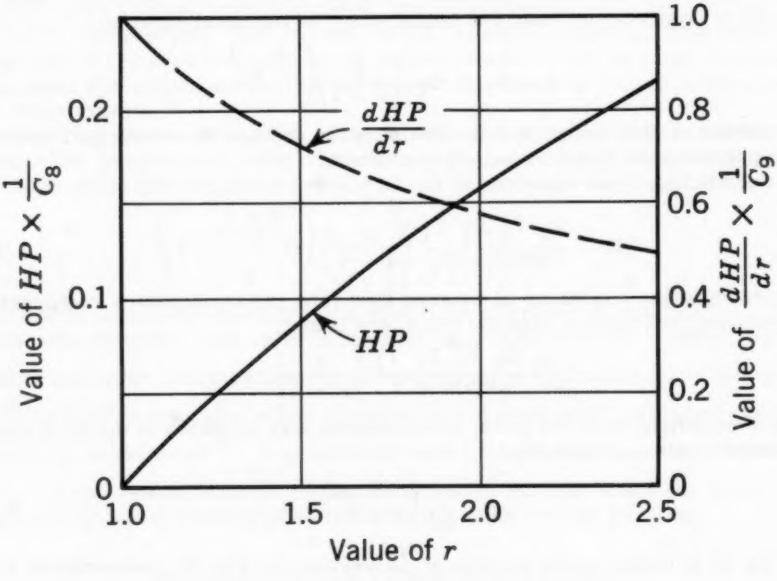

FIG. 10.—EFFECT OF r ON HP

the gas flowing in a pipeline will be greater at high compression ratio than at low compression ratio.

RELATIONSHIP OF COMPRESSION RATIO AND SYSTEM POWER REQUIREMENTS

In order to define the power requirements for gas compression in a pipeline under flowing conditions in terms of compression ratio the following equation will be used:

$$HP = \frac{W\ H}{33000\ e} \qquad (30)$$

in which e denotes compressor efficiency, W is the gas flow rate in pounds weight per minute, and H refers to the isentropic head in foot-pounds per pound. Resolution of this relation in terms of compression ratio may be accomplished by: (a) defining W in terms of standard cubic and specific volumes thus

$$W = \frac{Q_o}{60 \times 24\ V_o} \qquad (31a)$$

or

$$W = \frac{Q_o\ 144\ P_o}{1440\ R\ T_o} \qquad (31b)$$

in which Q_o represents flow rate in standard cubic feet per day and V_o the specific volume at standard conditions; and (b) defining the isentropic head in terms of compression ratio and temperature by the usual equation,

$$H = Z_1\ R\ T_1 \left(\frac{k}{k-1}\right)\left(r^{\frac{k-1}{k}} - 1\right) \qquad (32)$$

in which k is the ratio of specific heats for the gas and the subscript 1 denotes compressor inlet (pipeline outlet) conditions.

Substituting these equations in Eq. 30 yields

$$HP = \frac{Q_o\ P_o\ Z_1\ T_1}{330000\ e\ T_o}\left(\frac{k}{k-1}\right)\left(r^{\frac{k-1}{k}} - 1\right) \qquad (33)$$

by assuming the conditions of constant flow rate, gas temperature, compressor effeciency, and ratio of specific heats, and letting

$$C_8 = \frac{Q_o\ P_o\ Z_1\ T_1}{330000\ e\ T_o}\left(\frac{k}{k-1}\right) \qquad (34)$$

and substituting; then the power requirements may be stated in terms of compression ratio and a constant

$$HP = C_8\left(r^{\frac{k-1}{k}} - 1\right) \qquad (35)$$

Eq. 35 is shown as the relation of $\frac{HP}{C_8}$ versus r in Fig. 10. Referring to Fig. 10 and the preceding equations it is noted that as compression ratio approaches

1.0 the relation $\frac{HP}{C_8}$ approaches zero, and as compression ratio approaches infinity the relation $\frac{HP}{C_8}$ also approaches infinity but at a lesser rate of change.

The curve shown in Fig. 10 is quite uniform and the rate of change in $\frac{HP}{C_8}$ values with respect to r is undefinable by inspection. It is thus necessary to further investigate the slope of this curve by use of the derivative

$$\frac{dHP}{dr} = C_8 \frac{k-1}{k}\left(\frac{1}{r^{1/k}}\right) \qquad (36)$$

letting

$$C_9 = C_8 \frac{k-1}{k} \qquad (37)$$

then

$$\frac{dHP}{dr} = C_9\left(\frac{1}{r^{1/k}}\right) \qquad (38)$$

A curve representing this derivative is also shown in Fig. 10. By inspection it is seen that greater rates of change in $\frac{HP}{C_8}$ values with respect to r values occur at compression ratio of less than 1.5.

Consideration of the relationship of $\frac{HP}{C_8}$ versus r, only, might lead to the conclusion that higher line compression ratio would result in lower overall system power requirements; however, when considered in conjunction with the effect of compression ratio on line length, or station spacing, it is seen that increase of compression ratio in the higher ranges result in small increases in station spacing and proportionally greater increases in overall system power requirements.

To illustrate the preceding premise, the relationships of line length with respect to compression ratio and power requirements with respect to compression ratio are compared as follows:

$$\frac{HP}{L} = \frac{C_8\left(r^{\frac{k-1}{k}} - 1\right)}{C_2\left(1 - 1/r^2\right)} \qquad (39)$$

for which, within the constants, the conditions of pressure, temperature, flow rate, pipe diameter, and ratio of specific heats are assumed constant and in consistent units. As shown in Fig. 11 the values of $\frac{HP}{L}$ continuously decrease with respect to lessening values of compression ratio, and it is evident the rate of change in values of $\frac{HP}{L}$ is greatest at values of compression ratio of 1.10 and less. From this it is reasoned that the greatest savings in system power requirements would be attained at compression ratio of 1.10 and lower.

PIPELINE SYSTEM POWER REQUIREMENTS

To illustrate the relationship of compression ratio and pipeline performance, overall system power requirements were calculated for several line

sizes under various conditions of gas flow and are shown in Fig. 12. These calculated power requirements are for pipeline losses only in a system 1000 miles in length, and cover ranges of compression ratio, pipe size, and line inlet pressures, as noted in Fig. 12. Figs. 12 (a), 12 (b) and 12 (c) are based on line terminal outlet pressures equal to P_2 as determined from the relation $\frac{P_1}{r}$. This results in a penalty against the low compression ratio systems, because with P_1 constant the line terminal outlet pressure for a low compression ratio system is greater than for a high compression ratio system. However, this penalty does not seriously detract from the demonstration of the low compression ratio concept, for if the line terminal outlet pressure P_2 were made equal

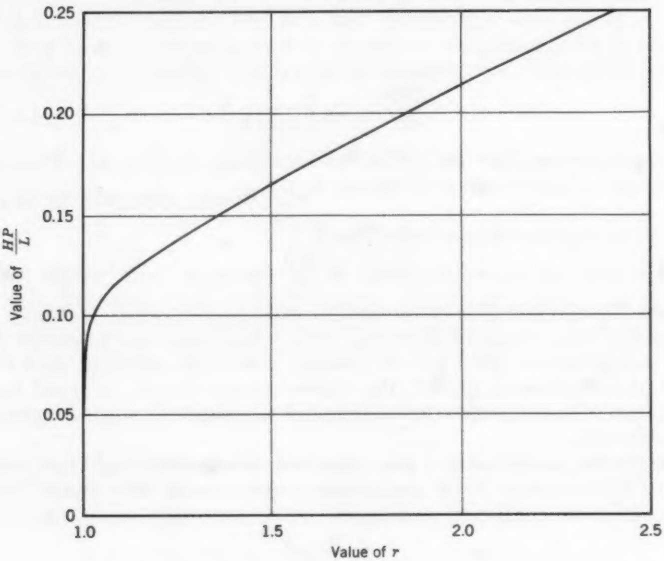

FIG. 11.—EFFECT OF r ON $\frac{HP}{L}$

for the various compression ratio systems the correction would favor the low compression ratio system and would make the comparison of overall system power requirements all the more in favor of the low compression ratio system.

To illustrate the difference between high compression ratio—low mean effective pressure and low compression ratio—high mean effective pressure systems, let us assume a 30 in. diameter pipeline flowing 600 MMCFD at 1,000 psia inlet pressure and 1.60 compression ratio. Overall power requirements for this system, from Fig. 12 (a), would be 130,000 horsepower, whereas for the same pipeline at 1.08 compression ratio, and other conditions the same, the overall system power requirements would be 82,000 horsepower. This

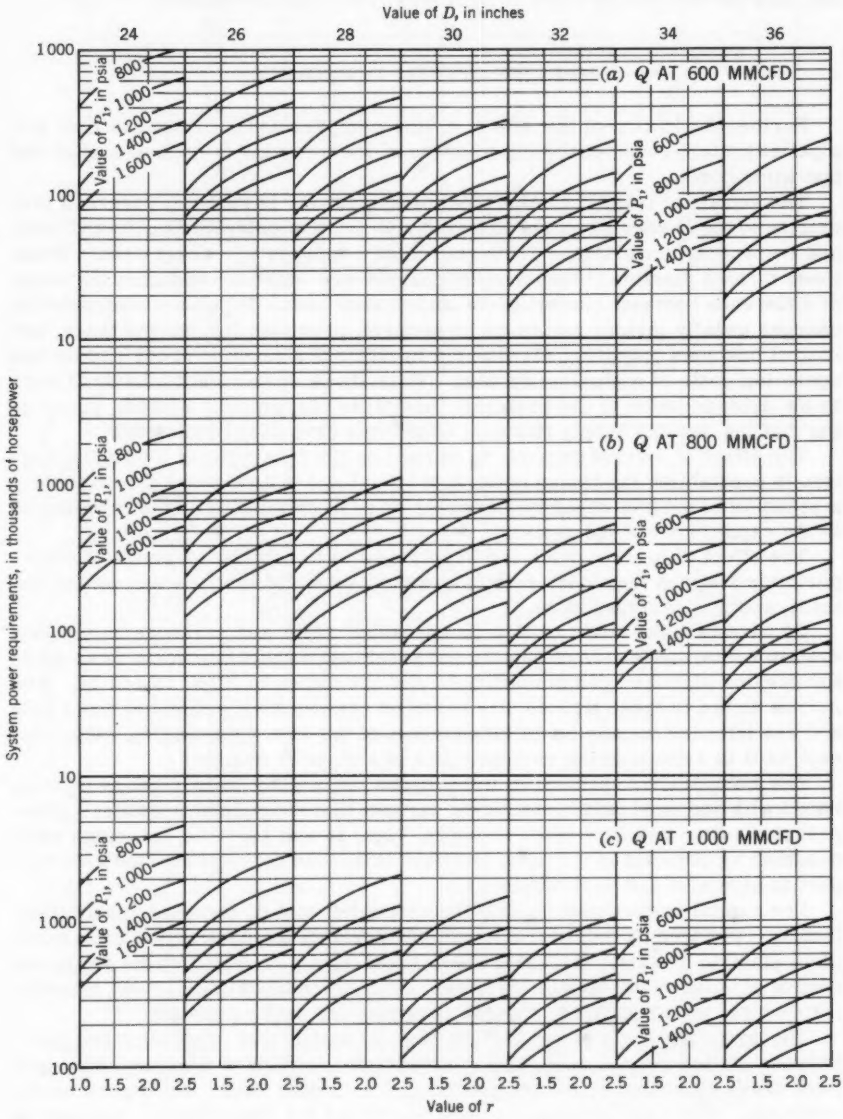

FIG. 12.—PIPELINE SYSTEM POWER REQUIREMENTS AT VARIOUS r, P, AND D VALUES

comparison indicates the possible savings, in both capital and operating costs, that may be obtained by a low compression ratio pipeline system.

PIPELINE SYSTEM ECONOMICS

Further evaluation of the effect of line compression ratio on gas flow in a pipeline system requires the introduction of the economic factors of capital and operating costs.

The economic feasibility of a pipeline system is, in general, governed primarily by the factors of market demand and price, supply availability and cost, and transportation distance from source of supply to a market area. From these factors pipeline transportation charges are established within the range of difference between market price and source cost. Pipeline transportation charges usually include return on investment, provision for income taxes, and cost of business operation, all of which in turn are a function of the capital and operating costs of a pipeline system. Thus these costs are the basic factors in the determination of the economic feasibility of a pipeline system, presuming that market and supply financial conditions have been established.

The effect of market demand, or volume, on the feasibility of a pipeline system is to establish the design criteria of initial and ultimate line flow rates and a schedule of system capacity increases. These criteria are in turn reflected in the capital cost of the system.

The effect of market price and supply cost is to establish a range of transportation charges that must reflect system operating cost, return on investment, and provision for taxes.

To illustrate the effect of line compression ratio and pressure on pipeline system costs, estimates of capital and break-even operating costs were made for various pipeline system conditions and are shown in Figs. 13 and 14. The curves shown in these figures are based on comparative estimated costs only and are intended merely as an illustration of the low compression ratio concept as it is related to the various costs of a pipeline system.

The comparative estimates were based on a 1000 mile pipeline system length with assumed unit costs for the various line sizes, inlet pressures, compression ratio, and flow rates shown in Figs. 13 and 14. The unit costs were assumed as constant in all cases possible otherwise they were varied with respect to pipe size and wall thickness.

The capital costs shown include the estimated cost of material, installation, testing, contingency, engineering, and management of construction for a complete pipeline system. Excluded from these capital costs are the estimated cost of pipeline right-of-way, damages, land, communication system, classification pipe, metef stations, standby compressors, and equipment.

The operating costs shown include the estimated cost of pipeline and compressor station maintenance, labor, supervision, and fixed charges. Excluded from these estimated costs are provision for income taxes and return on investment. The fixed charges include allowance for depreciation, interest on bond debt, and ad valorem taxes; all on a first year basis.

The influence of line compression ratio on system costs shown in Figs. 13 and 14 appears as a lowering of both capital and operating costs with respect

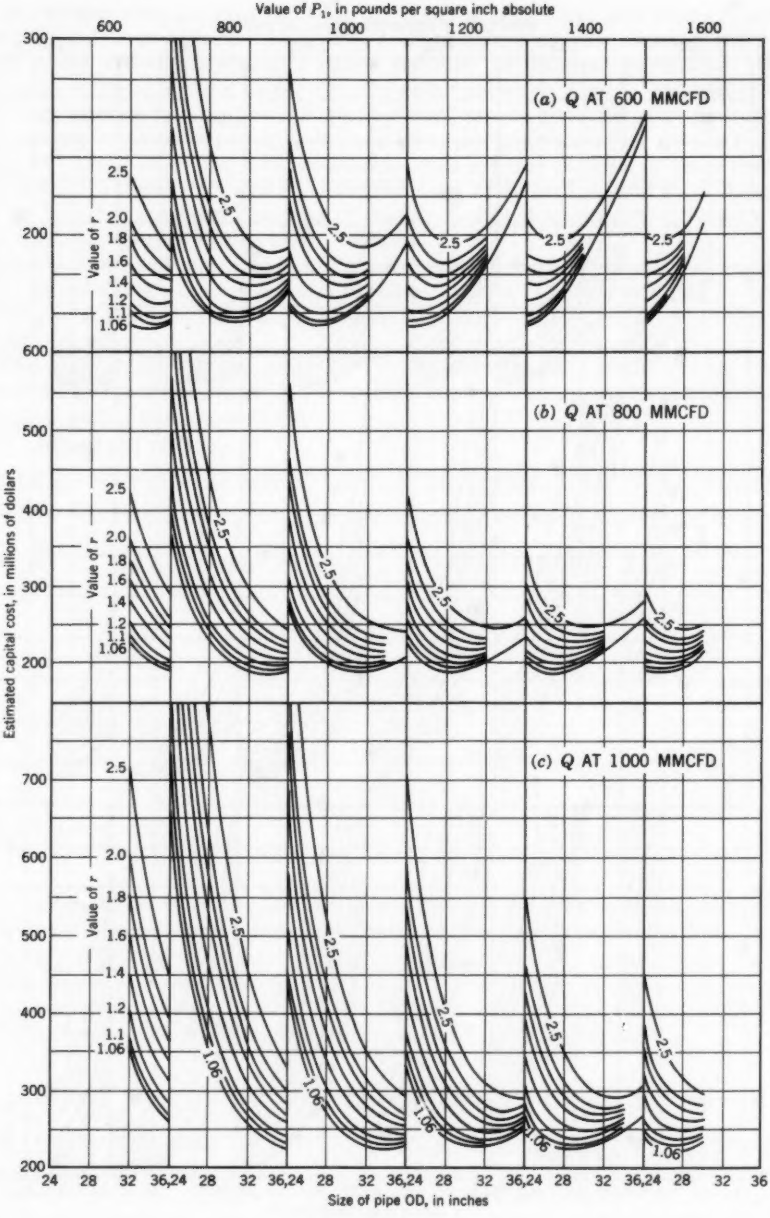

FIG. 13.—PIPELINE SYSTEM ESTIMATED CAPITAL COSTS AT VARIOUS r, P, AND D VALUES

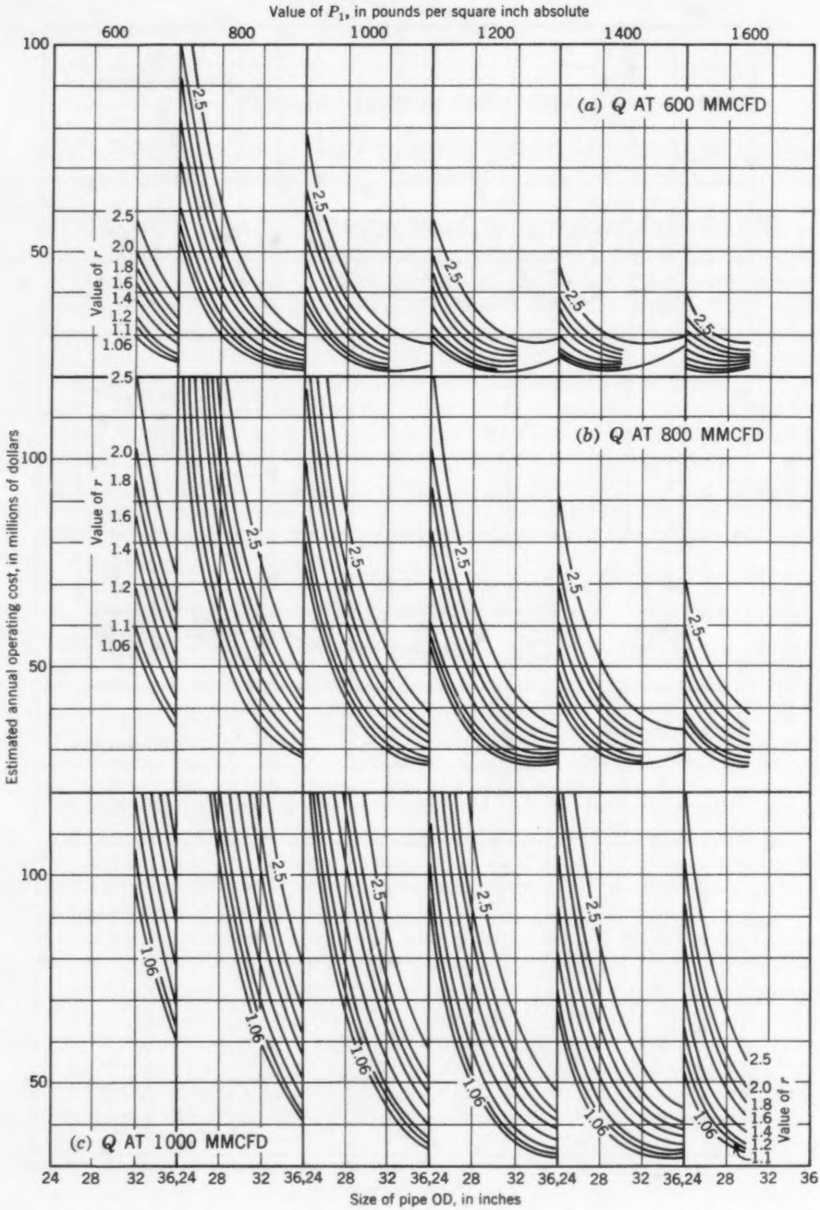

FIG. 14.—COMPARATIVE ESTIMATED OPERATING COSTS AT VARIOUS r, P, AND D VALUES

to decreasing compression ratio for all cases of pipe size, line inlet pressure and flow rates considered. The diminishing effect of compression ratio on these costs in the high pressure range, and also the diminishing effect of compression ratio on system power requirements shown in Fig. 12, are indicative that the relation of compressor station cost versus pipeline cost decreases with respect to increasing pipe size and line inlet pressure; thus for the larger sizes of pipe at high line inlet pressures, the greater portion of both capital and operating costs for a system is represented by investment and fixed charges for the pipeline; the lesser portion of these costs is represented by investment and fixed charges for compressor stations.

The influence of line compression ratio and mean effective pressure as related to the financial aspects of a pipeline system is shown in Table 2; estimated costs are compared for line size, inlet pressure, and compression ratio conditions, as noted.

The comparison of cost shown in Table 2 were taken at random from Figs. 13 and 14 and are intended only to point out the economic potential of low compression ratio pipeline systems.

TABLE 2.—COST COMPARISON OF LOW AND HIGH COMPRESSION RATIO SYSTEMS

d, in inches	L, in miles	Q, in MMCFD	P_1, in psia	r	Capital cost, in millions of dollars	Operating cost, in millions of dollars per annum[a]
24	1000	800	1600	1.06	190	34
36	1000	800	800	1.40	206	34
28	1000	1000	1400	1.06	225	40
36	1000	1000	800	1.40	256	51
36	1000	1000	800	1.06	225	41

[a] First year costs.

It is noted that line inlet pressure is also a major factor and has a significant effect on system economics in certain cases of line size and flow rates. However, this analysis is concerned primarily with line compression ratio; consequently, rigorous analysis of line inlet pressure effects, in conjunction with compressor ratio, on system economics has been omitted in order to avoid the confusion of having too many subjects under inspection.

CONCLUSIONS

To briefly review the relationship of compression ratio and the various gas flow factors as described herein, it is seen that the curves for these factors, as shown in Figs. 4 through 11, all have the same characteristic of curvature; that is, the slope is greatest at minimum values of compression ratio, and the slope changes at a lessening rate as compression ratio increases. Several of these curves, notably the relationship of line flow versus compression ratio,

indicate limits of compression ratio above which any increase will result in such a small gain in the gas flow factor considered that no further economic benefit can be realized by raising the line compression ratio. It has been also demonstrated that increasing line compression ratio to gain greater lineflow rates or station spacing results, at some limiting value of compression ratio, in excessive overall system power requirements and capital costs.

In large diameter pipelines the major capital expense is for the cost of pipe and pipe installation as compared to cost of compressor stations and other nominal pipeline facilities. Also during the early years of life of a pipeline system, the largest items of operating cost are those for interest on debt and depreciation. These fixed charges, plus provision for retirement of debt, are a direct function of system capital investment; consequently, the greater part of system operating costs and debt retirement is attributable to the capital cost for pipe and pipe installation.

Any major savings in pipeline system operating costs, therefore, must be found in the pipe, either through variations in wall thickness and size or by making better use of the physical properties of the pipe material. The most promising of these possibilities is that of making better use of the physical properties of the pipe through application of the low compression ratio principle to gain greater overall cost savings and efficiency for a pipeline system.

The increased number of compressor stations required for a low compressor ratio system will not cause undue hardship in costs for such a system but, rather, through simplified standardized station design and lowered system power requirements the low compression ratio system will, in general, have lower capital and operating costs than a comparable high compression ratio system.

With the advent of modern control, communications systems, and equipment, the low compression ratio gas transmission pipeline system is ideal for the application of simplified compressor installation and the use of fully automatic unattended compressors, particularly in conjunction with remote computer control from a central dispatch point.

The operation of a low compression ratio pipeline system will pose no unusual problems from a control standpoint, for the reliability and reasonable cost of installation and operation of modern communications systems, automatic control equipment, instruments, and computer control equipment has been proven in pipeline service.

In the past any application of the low compression ratio principle to gas pipeline system design has been limited by the high cost of installing and operating a large number of compressor stations. However, recent technical advances in pipeline compressor design has been such that small compressors of low head-high volume characteristics and suitable for low cost installation and operation are available for service in low compression ratio pipeline systems.

The application of the low compression ratio concept to the design of gas pipeline systems is feasible and can result in important economic benefits through lowered capital and operating costs for such a system. Existing gas pipeline systems can be modified or expanded by conversion to low compression ratio operation, in lieu of looping, to gain the benefit of either increased flow rate with a minimum capital investment or lower operating cost for a given line flow rate.

APPENDIX.—NOTATION

The symbols used in this paper are listed here for ease of reference and for the aid of discussers:

C_1, C_2, C_3 . . . constants as noted;

d = internal diameter of pipe, in inches;

e = efficiency of compressor;

f = resistance coefficient, dimensionless;

G = specific gravity of gas (air equals 1.00);

H = adiabatic head required for gas compression, in foot-pounds per pound;

HP = power required for gas compression, in horsepower;

K = numerical constant, 1.6156;

k = ratio of specific heats of gas;

L = line length, in miles;

P = pressure, in psia;

P_m = mean effective line pressure, in psia;

P_o = standard pressure base, in psia;

P_1 = line inlet pressure, in psia;

P_2 = line outlet pressure, in psia;

Q = flow rate of gas, in cubic feet per hour;

r = compression ratio;

T = temperature of flowing gas, in degrees Fahrenheit absolute;

T_o = temperature base, in °F absolute;

T_1 = line outlet temperature, in °F absolute;

T_2 = line inlet temperature, in °F absolute;

V_1 = volume of gas in packed line, in standard cubic feet;

V_2 = internal volume of pipeline, in cubic feet;

Z = compressibility factor for gas, dimensionless;

ρ = specific weight of gas, in pounds per cubic foot;

ρ_m = specific weight of gas at mean effective line pressure, in pounds per cubic foot; and

ρ_o = base specific weight of gas, in pounds per cubic foot.

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FUNDAMENTALS OF CATHODIC PROTECTION

By Jack W. Pierce,[1] F. ASCE

SYNOPSIS

Pipeline engineers are realizing more and more, the importance of considering the application of cathodic protection systems in conjunction with pipeline coatings to protect and extend the life of pipelines. The staggering yearly cost of corrosion on underground pipelines, amounting to as much as between 2% and 5% of the original investment, justifies the use of substantial engineering effort to reduce or mitigate this waste.

A basic understanding of the causes of corrosion, principles of cathodic protection and an ability to at least assist in the design of cathodic protection systems are of considerable value to the present day pipeline engineer.

Application of coatings and cathodic protection systems should always be economically justified. This requires thorough investigation by competent engineers in analyzing the expected cost of corrosion, cost of protection systems and evaluating the results. Only after this has been accomplished can an intelligent decision be made relative to the merits of installing cathodic protection.

INTRODUCTION

It is generally recognized by pipeline design and operating engineers that use of coatings and installation of cathodic protection systems should receive major consideration in the design and installation of any underground piping

Note.—Discussion open until February 1, 1962. To extend the closing date one month, a written request must be filed with the Executive Secretary, ASCE. This paper is part of the copyrighted Journal of the Pipeline Division, Proceedings of the American Society of Civil Engineers, Vol. 87, No. PL 2, September, 1961.

[1] Supervisor of Engrg. Standards, Southern California Gas Co., Los Angeles, Calif.

system. Essentially, a combination of an adequate coating and a cathodic protection system when needed gives as close to the ultimate in pipe protection as can be expected in modern pipeline operations.

Every pipeline engineer has experienced in some form or another the effects resulting from the many types of corrosion that occurs on underground pipelines. Engineers are also well aware that damage from corrosion takes place on metals both above and under the ground. It has been determined that one ampere of current flowing from a steel surface through an electrolyte can cause dissolution of approximately 20 lb of the metal in 1 yr.[2] Actually, the yearly cost of metallic corrosion throughout the world has been estimated to amount to $10,000,000,000, and that in the United States, in spite of up-to-date methods of cathodic protection, pipeline corrosion alone costs in excess of $600,000,000 per year.[3] One author estimates that the annual cost of pipeline corrosion because of leak repairs, and so on may amount to as much as between 2% and 5% of the original investiment.[4] These cost figures certainly justify use of extreme measures to eliminate or certainly mitigate this very serious problem. Through proper use of coatings and cathodic protection, if it is needed, the corrosion costs may be replaced by coating and protection costs of between 1% and 2% of the original investment.[4] This cost reduction is substantial enough to be highly significant. In addition, there are many other tangible and intangible benefits that are particularly apparent in a utility type operation.

CORROSION DEFINED

Corrosion can be defined as the destruction of a metal by an electrochemical reaction in which a chemical change occurs accompanied by a transfer of electrical energy. Pipelines, as well as all metals, are constantly in the process of reverting to the elements of their origin and returning to a lower energy state. All iron compounds, once they are exposed to the elements, start to return to their natural ores. Both the processes of corrosion and cathodic protection are fundamentally very simple. The various types of environment encountered underground are responsible for making the problem of mitigating corrosion through cathodic protection extremely complex.

The chief contributing factors to underground corrosion are the presence of moisture, oxygen and soluble salts in the soil, as well as the permeability of the soil to these substances. Moist soil acts as the electrolyte, and the hydrogen ion concentration in combination with other ions from salts dissolved in the soil determine the electrical resistivity as well as the chemical properties of the soil. Oxygen from air or other compounds stimulates corrosion by combining with the hydrogen formed during the corrosion process. If hydrogen were allowed to accumulate, it would form an insulating barrier tending to stop or reduce corrosion. This process is known as polarization. However, if sufficient oxygen is present to combine with the hydrogen, this insulating barrier can not be formed and the rate of corrosion will not decrease. The

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2 "Interference Effects in Cathodic Protection," by Marshall E. Parker, Oil and Gas Journal, 1956.

3 "Cost of Corrosion to the United States," by Herbert H. Uhlig, Corrosion, January, 1950, pp. 29-33.

4 A Collection of Papers on Underground Pipeline Corrosion, "Economic Aspects of Cathodic Protection," by Roy M. Wainwright, Vol. II, First Edition, 1958.

products of corrosion may accumulate, and one of the unique factors in the corrosion process is that the products of corrosion may actually build up and protect against further corrosion.

Fig. 1 shows the classic example of the very simplest form of a galvanic cell composed of dissimilar metals. The electrical system in a flashlight battery consists of an electrolyte, a carbon cathode and a zinc anode electrode. The carbon cathode is surrounded by the electrolyte, which provides a path for metallic ions traveling from the zinc anode to the carbon cathode. In order to complete the circuit, a connection is made between the cathode and the anode allowing the current to flow. Thus, a simple electrical current flows in a closed system. As the current leaves the zinc, it carries small ion particles with it. When the zinc ions are dissolved in the electrolyte, they are exchanged for ions of hydrogen which collect on the carbon rod. The zinc anode or electrode will ultimately be destroyed by the current flow.

BASIC CAUSES OF CORROSION CURRENT

There are four basic causes of corrosion current:

1. Direct chemical attack.
2. Microbiological attack.
3. Calvanic corrosion caused by dissimilar metal or by differential electrolyte conditions.
4. Stray currents.

Direct chemical attack may occur in soils on which acid chemicals or fertilizers have been placed creating soil characteristics which encourage corrosion. We are not too concerned with this type of corrosion, because it does not occur very often. However, there have been rare instances where fertilizers placed on lawns or plants have filtered through the soil and around a pipeline resulting in a direct chemical attack type of corrosion.

The second type, microbiological attack, is not completely understood at this time but as time goes on more is being learned about this type of corrosion through field and laboratory investigations. In this type of corrosion, certain types of bacteria that inhabit the soil are particularly active in heavy, poorly drained, swampy areas containing organic material. Corrosion results when the anaerobic bacteria in the soil reduces and converts sulfates to sulfides. Most corrosion engineers agree that the proper application of a coating, combined with adequate cathodic protection, will be sufficient to mitigate corrosion from microbiological attack. There is also general agreement that the level of protection must be higher than in areas where bacteria is not a problem.

By far the most serious type of corrosion related to the pipeline industry is galvanic corrosion. It is the largest single cause of corrosion in underground piping systems. Fig. 2, 3, and 4 illustrate examples of dissimilar metal corrosion, a form of galvanic cell corrosion. Fig. 2 shows, in a very simple form, a steel pipe with a copper service connected to it. The steel pipe acts as the anode, or sacrificial metal, the copper service as the cathode. The current flows from the steel pipe through the soil, or electrolyte, to the copper service then back through the steel pipe. Thus the corrosion occurs on the steel pipe. Fig. 3 shows the pitting effects of this type of corrosion on a

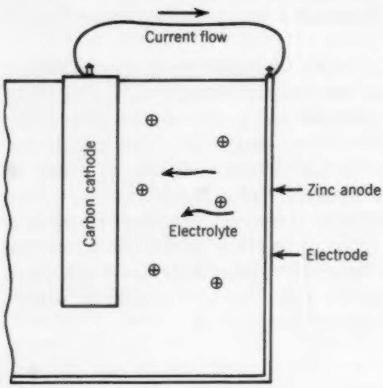


FIG. 1.—FLASHLIGHT BATTERY

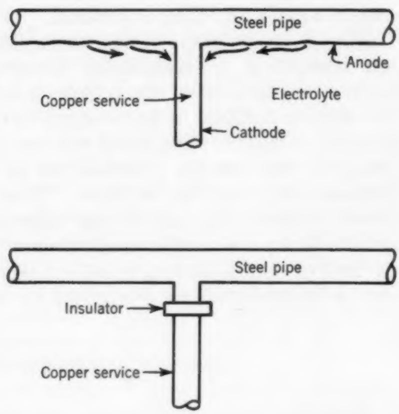


FIG. 2.—GALVANIC CELL ACTION—DISSIMILAR METAL CORROSION

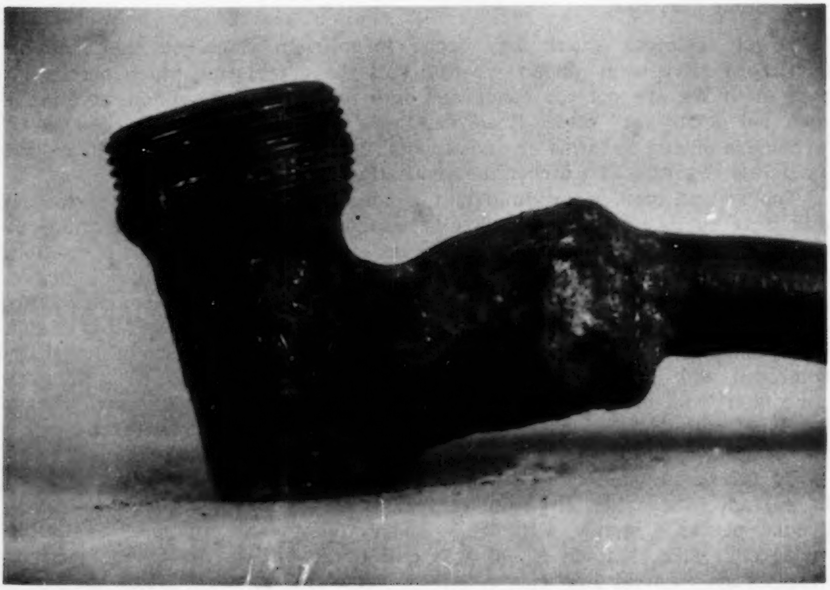


FIG. 3.—GALVANIC CELL CORROSION OF CONNECTION BETWEEN COPPER SERVICE AND STEEL SERVICE TEE

steel service tee when it was directly connected to a copper service. The type of connection shown in Fig. 4 should also be avoided. In this instance, a copper service was brazed to a 1/2 in. steel nipple. The nipple in turn was threaded into a bronze valve. Note the pitting in the nipple resulting from corrosion. This type of corrosion is very readily controlled by application of an insulator between the copper service and the steel pipe as shown in the lower portion of Fig. 2. The insulator prevents corrosion by stopping the flow of ions and breaks the electrical circuit.

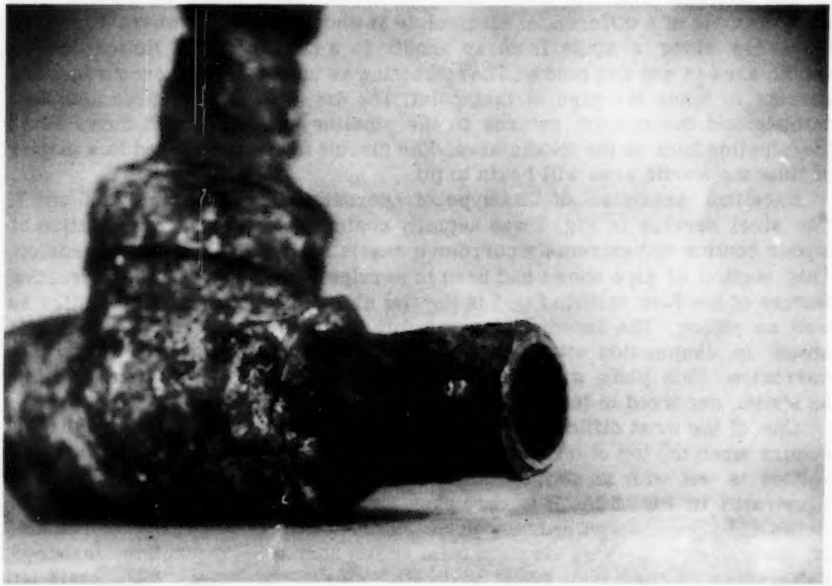


FIG. 4.—GALVANIC CELL CORROSION OF CONNECTION BETWEEN BRONZE VALVE, STEEL NIPPLE AND COPPER SERVICE

All metals have a natural potential. A part of the galvanic series together with each metal's potential is as follows:

METALS	VOLTS	
Magnesium	-2.34	
Aluminum	-1.67	
Zinc	-0.76	
Iron	-0.44	
Brass	-0.28	
Hydrogen	0.00	Reference
Copper	+0.34	
Gold	+1.36	

Using hydrogen as a reference, the metals have been classified as to negative and positive voltage in proper sequence. Connecting any two of these metals

together in a electrolyte will cause current to flow resulting in corrosion of the anode metal. Magnesium at -2.34 v is the most anodic of the common metals; as such this is the most popular type of anode. The difference between copper and iron would be their algebraic sum or 0.78 v and this is the primary reason why these metals should not be connected without insulating. Although the galvanic series chart shows a difference in potential of 1.90 v between magnesium and iron, the actual measured difference in the field will vary between 0.9 v to 1.5 v. The actual difference in potential between metals is directly dependent on the electrolyte.

The galvanic cell has many different forms when attacking a pipeline. A good example of a differential electrolyte is shown in Fig. 5, where a pipeline traverses along a route from an anodic to a cathodic area. Notice that the anodic area is wet and muddy. The soil acting as an electrolyte encourages the current to leave the pipe at that point. The dry, well aerated area acts as a cathode and the current returns to the pipeline at this point. It then follows the pipeline back to the anodic area. The circuit is completed and in a matter of time the anodic area will begin to pit.

Excellent examples of this type of corrosion are shown in Fig. 6 and 7. The steel service in Fig. 6 was actually coated, however, the combination of a poor coating and extremely corrosive desert soil accelerated the corrosion. This section of pipe shown had been in service less than 5 yr. An interesting feature of the 3-in. main in Fig. 7 is the flat slab indentation characteristics as well as pitting. The indentations probably resulted from anaerobic bacteria attack in conjunction with a galvanic cell. Fig. 8 is an example of extreme corrosion. This plate was placed in a very corrosive soil. Complete pitting, as shown, occurred in less than 2 yr.

One of the most difficult of all pipeline corrosion areas to find and protect occurs when the top of the backfill around the pipeline is well aerated and the bottom is wet with an oxygen deficiency, setting up small galvanic cells, as illustrated in Fig. 5(b). It is very easy for current to flow from the wet area to the dry area, causing pitting to occur on the bottom of the pipe. Unfortunately, the current in these small galvanic cells cannot be accurately measured. Differences in the metal itself will also cause galvanic cells. Mill scale left on the pipe causes considerable corrosion because it is cathodic to the pipe and has a significant potential difference from steel. Impurities in the steel and stresses or strains in the metal may also result in galvanic cell corrosion.

The fourth general type of corrosion occurs when stray currents are imposed upon pipelines. The classic example of this type of corrosion would be a pipeline installed under and adjacent to an electrified railway as shown on Fig. 9(a). The DC generator applies overhead current which is picked up by the connection between the transmission line and trolley. The electrical flow is then down to the rail and back to the generator station. Actual experience shows that stray currents quite often leave the rails and jump to the closest available metal which may be an underground pipeline ultimately resulting in corrosion of the pipeline. As shown on Fig. 9, this type of corrosion can be eliminated by applying a drain bond between the pipeline and the generator station allowing the current to flow from the pipeline back to the electrified railway system, again completing the circuit. Fig. 9(b) shows a typical cathodic protection interference problem. Current supplied by the rectifier station flows to the anodic ground bed and then disseminates in a wide area. If an unprotected pipeline passes through the area, it would naturally pick up stray cur-

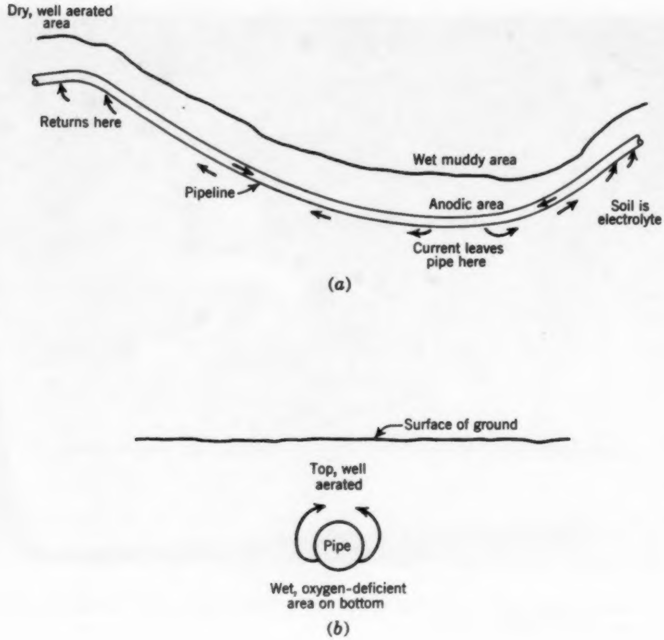


FIG. 5.—LONG AND SHORT GALVANIC CELL CORROSION

FIG. 6.—GALVANIC CELL CORROSION OF 3/4 IN. SERVICE PIPE WITH COATING

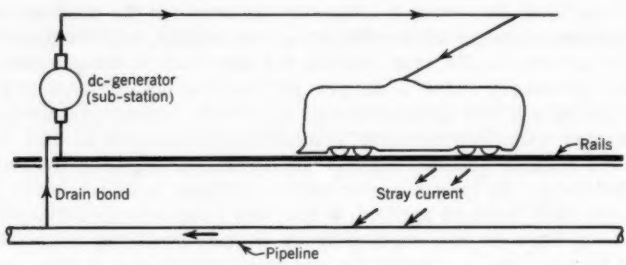
FIG. 7.—GALVANIC CELL CORROSION OF ANAEROBIC BACTERIA CORROSION OF 3 IN. STEEL MAIN

FIG. 8.—GALVANIC CELL CORROSION OF STEEL PLATE INSTALLED LESS THAN 2 YR

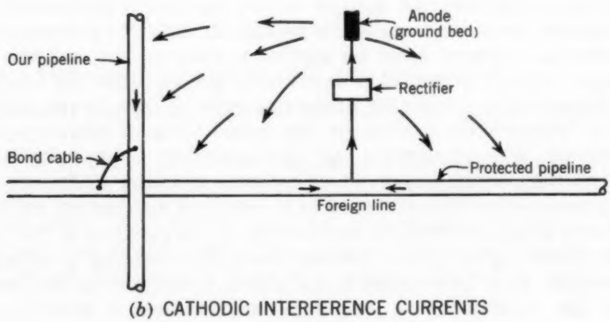
rents. Again a bond cable is installed from the unprotected line to the protected line completing the circuit and allowing the current to drain back to its original system.

FORMS OF CORROSION

Basically, there are several forms of corrosion but the two most common are rusting and pitting. Pitting, as mentioned previously, is the most serious form of corrosion and results from the continued flow of electrical current and ions from the same point on the pipeline. The pits gradually get deeper



(*a*) CURRENT FROM STREET RAILWAYS



(*b*) CATHODIC INTERFERENCE CURRENTS

FIG. 9.—STRAY CURRENT CORROSION

until ultimately they break through the wall of the pipe. Rusting is, of course, essentially the same process except that it is not usually concentrated at one point. In both underground and above ground corrosion, the first step is the formation of ferrous hydroxide. Reaction with oxygen results in the formation of ferrous or ferric oxide (rust) which results in rusting on bare pipe held in storage. Dew collects on exposed pipe, and, because of differences in oxygen content in different areas of each small drop of moisture, as well as mill scale on the pipe, impurities in the metal and so on, current flows and rusting occurs. The magnitude of the current is so small that considerable time must elapse before appreciable damage occurs. Because there are thousands of these tiny cells formed, the pipe surface is usually attacked in a fairly uniform manner. In addition, contributing to this uniform attack is the fact that

heat from the sun dries up these tiny cells during the day and when they reform at night they may form at slightly different locations. This rust builds up on the pipeline and, as has been mentioned previously, may ultimately provide protection against further corrosion.

PREVENTION OF CORROSION

An examination of corrosion must lead to the problem of its prevention. The solution may require an application of a coating or cathodic protection or a combination of both. What is hoped for, but never achieved is the perfect coating, with no "holidays." The pipeline is completely protected, therefore no current can flow. However, if a break does occur in the coating because of rock penetration, damage to coating or other causes, and the pipeline is not cathodically protected, the ions leaving the pipe wall at these holidays in the coating will gradually make a deeper pit building up products of corrosion around the pit in their flow to some kind of a cathode. Ultimately, the pit breaks through the pipe wall. Unfortunately, in localized pitting such as this, corrosion is much more serious because the current leaving the pipeline is concentrated at these holidays. To prevent corrosion at these holidays in the coatings, cathodic protection must be applied. It has long been accepted that there is no perfect coating because the economics of coating pipelines are such that the cost would be prohibitive. Therefore, the combination of a coating that does a reasonably good job, combined with cathodic protection, gives what is generally accepted as the best method of pipeline protection.

Cathodic protection may be defined as a process consisting of impressing a current from some external source on the pipeline in such magnitude that the entire pipeline becomes negative to the soil. In order to prevent corrosion, sufficient external current must be applied to polarize the cathodic areas so that their open circuit potential is equal to or greater than the anodic areas. The actual installation of cathodic protection may be done in one of two ways: installation of magnesium anodes, or the installation of cathodic protection rectifier stations. Fig. 10 shows a typical magnesium anode installation. The magnesium anodes, usually cylindrical castings weighing 32 lb, are placed in a specially prepared backfill enclosed in a cloth bag and buried within 10 ft of the pipeline and at a pipe depth so that the top of the anode is at the same elevation as the bottom of the pipe. The lead wire is brought up to a test location and a connecting wire is attached to the pipeline completing the installation. The anode life varies as a result of environment in which it is buried.

Advantages gained by the installation of anodes are as follows:

1. There is no cathodic interference.
2. It is generally less expensive when small amounts of current are required.
3. No outside source of power is needed.
4. They may be placed close to the pipe.

There are, however, some disadvantages insofar as the application of magnesium anodes are concerned:

1. If pavement must be cut for the installation, this increases the expense.
2. The use is limited to lower resistivity soils.
3. The anodes have to be replaced every 10 or 20 yr depending on their output.

The second type of installation, that of a cathodic protection rectifier station, is shown on Fig. 11. As canbe seen, the rectifier station converts alternating current to direct current and applies the direct current to the ground bed, generally consisting of graphite or Duriron rods. The current in turn leaves the ground bed and travels back to the pipeline to be protected. By connecting the pipe with the rectifier station, the circuit is completed and the pipe is under protection at all times. The advantages of rectifier installations are as follows:

1. It is less expensive when large amounts of current are required and it requires fewer installations.
2. It may be used in high resistivity soil.
3. It is possible to control current output.
4. It can operate for longer periods of time without replacement.

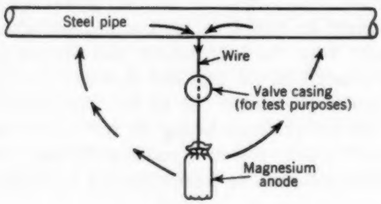


FIG. 10.—MAGNESIUM ANODE INSTALLATION

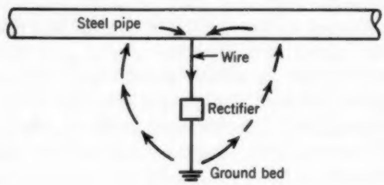


FIG. 11.—RECTIFIER STATION INSTALLATION

There are also disadvantages for this type of installation:

1. Because of the large currents, it cannot be used in congested underground areas.
2. Generally, more current is required because the source of current is localized rather than distributed as in the case of magnesium anodes.

The break-even point between the use of magnesium anodes and rectifier stations is between 2 and 3 amp. When more current than this is required to protect a pipeline, it is usually more economical to install a rectifier station.

DESIGN OF CATHODIC PROTECTION SYSTEMS

The design of cathodic protection systems requires an experienced corrosion engineer along with very thorough and complete field investigations. The general criteria for determining the need of cathodic protection is that any soil with a resistivity of less than 10,000 ohm cm can be considered as corrosive. Soil with a resistivity of less than 1,000 ohm cm is extremely corrosive while soils with a resistivity of over 10,000 ohm cm are usually not corrosive and may be generally classified as bare pipe areas. The ohm centimeter which is the basic unit of resistivity is the resistance in ohms of one cubic centimeter of the material in question.

The first step in the design of a cathodic protection system would be to make a soil resistivity survey along the route of the pipeline. There are many methods of making these tests. One method uses a soil rod to determine soil resistivity. This instrument is composed of a rod with the tip insulated from the rest of the rod. Attached to the rod is a set of batteries along with an alternator to be used in applying an electrical current from the tip of the rod to the soil. The resistivity of the soil at the depth of the tip is read directly in ohm centimeters. This is a relatively easy and rapid method of making a soil survey.

A more involved and accurate method is to megger along the pipeline route. Four poles equally spaced are driven into the soil along the longitudinal axis of the proposed pipeline. The megger has a built-in generator which applies alternating current through the soil. A combination meter which integrates the voltage and current gives the necessary readings. These readings give the average soil resistivity to a depth equal to the spacing between rods. One other additional test that may be used in conjunction with either of the two previously mentioned is the Corfield nipple and can tests. In this test, soil samples taken from along the pipeline route are brought into the laboratory and placed in small cans. A wired steel nipple is also placed in the can and direct current applied through the nipple into the soil. This is continued for 24 hr. The nipple is measured before and after the test, the weight loss being an indication of soil corrosivity. Regardless of the method used, the soil resistivity data is plotted and the areas with extremely corrosive soils are specified for cathodic protection in addition to the pipeline coating.

Once the pipeline has been installed, the section to be protected is insulated electrically from all other piping. Test leads, usually installed by the Cadweld process are placed at intervals along the pipeline. Test leads are also installed on each side of every insulator. A decision is then made whether to install anodes or rectifier stations. If the use of magnesium anodes is indicated, one criteria for their installation is to install one anode for each 3,000 ft of 3-in well coated equivalent main. Anode installations are usually limited to areas with a soil resistivity of 2,500 ohm cm or less.

If the decision is made to install a rectifier station, electrical tests must be made. Generally, a welding machine is set up to apply current to a temporary ground bed. This installation is made approximately 200 ft from the pipeline. Directly opposite the ground bed and over the center line of the pipeline a copper sulfate half cell reading is taken, measuring the pipe to soil potential. The voltage on the welding machine is adjusted so that the maximum reading on the cell is -2 v. Higher voltage would damage the coating. Copper sulfate readings are taken each way along the long axis of the pipe until the readings indicate -0.85 v. This has been accepted as the minimum pipe to soil potential necessary for adequate protection. On a well protected pipeline with a coating resistance of 300,000 ohms sq ft, one rectifier station may cover up to 50 miles of pipeline.

Following installation of the necessary rectifier stations, the area is put on routine, that is, readings are taken at the lowest pipe to soil potential approximately every 3 months. If the readings fall below -0.85, the voltage at the rectifier station is increased accordingly. Any appreciable differences in readings requires immediate investigation. Rectifier readings are made every month and any changes in output also requires immediate attention. If the pipe coating should begin to deteriorate rapidly so that current requirements are increased, serious corrosion trouble can be expected.

Long line currents do not occur significantly on newly coated pipelines. However, they can be measured by connecting a voltmeter between two of the test leads inserted on the pipeline. This will give potential readings (because the resistance of the pipe is known, application of ohms law determines the current). Corrosion engineers are much more concerned with short line currents which, unfortunately, are almost impossible to find or measure. The procedure, as previously outlined, is generally followed for the installation of both new transmission and distribution pipelines.

One method used to check the presence of "holidays" in a coated pipeline after it has been installed is by use of a Pearson Detector. This instrument will indicate, as it is being passed along the longitudinal axis of the pipeline, whether or not there are breaks in the coating. If it appears that "holidays" are present and that they are of sufficient magnitude, it is highly desirable that the pipeline be excavated and repairs made.

PROTECTION OF EXISTING PIPELINES

At times it may be desirable to consider applying cathodic protection to a previously installed coated pipeline if the coating appears to be deteriorating. The criteria for making this decision is the coating leakage resistance of the pipeline coating. This is determined by applying a temporary current to the coated pipeline using batteries and a ground bed. Test leads are installed approximately 200 ft apart in various sections of the pipeline depending on type of soil. Voltage readings are taken and the current flowing in the pipeline is calculated. At the same time, pipe to soil potentials are taken with a copper sulfate cell between the two ends of the section under consideration. The total resistance of the coating in ohms is calculated using the pipeline current and pipe to soil potentials. The resistance is multiplied by the total square footage in the section to be protected. A criteria of 300,000 ohm sq ft is considered good coating leakage resistance. Any coating with a resistance of less than 100,000 ohms sq ft should be considered for application of cathodic protection.

If, after a study of the coating leakage resistance results, it is decided that it will be necessary to consider cathodically protecting the existing pipeline, the next step consists of making an economic survey to determine if the cost of cathodic protection would be less than the anticipated leak repair costs extended over the period of the remaining life of the pipeline. Again, if the results indicate it is desirable and feasible to install cathodic protection, the same general procedure is followed as would be the case with a new pipeline. A soil survey is made to determine the soil resistivity and to specify the sections of the pipeline to be protected. A decision is made as to the installation of anodes or rectifier stations, and the area to be protected is then insulated from all other piping. Pipe to soil potential readings are made after the installation of cathodic protection to determine if protection is adequate, corrections are made if necessary, and the area is put on routine. Again test readings are made every 3 to 6 months.

In areas where stray currents may affect the pipeline, it may be desirable to measure current with a continuously recording device giving 24-hr readings. It is most important that cathodic protection be applied on a continuous basis since intermittent or partial protection is, in many cases, poorer than no protection at all. Generally, the routine test readings are taken by operating departments and sent to the corrosion engineer for analysis. When protection is

not up to prescribed standards, maintenance work should be done immediately in order to correct the situation.

LIMITATIONS OF CATHODIC PROTECTION

There are many reasons why cathodic protection is not always effective:

1. Protection may not be continuously maintained.
2. The existing pits may be so nearly through the pipe wall that current will not penetrate to the bottom of the pits. This might be the problem when applying cathodic protection to existing pipelines.
3. Unbonded coating may act as an insulating shield to cathodic protection current, but water which gets in between the coating and the pipe causes corrosion to continue.
4. Heavy rust and scale built up on the pipe in dry desert areas may act as a shield similar to unbonded coatings.
5. Problems of applying cathodic protection may be so great that it is not possible or feasible to do so. Downtown congested areas are an excellent example. Too many substructures prohibit protection of old bare main.
6. In bare pipe areas soil is not so corrosive and cathodic protection is unnecessary.

CATHODIC INTERFERENCE

Another problem that is becoming more prevalent in this field is that of cathodic interference. Cathodic interference may be defined as the damage to one company's pipeline resulting from the operation of another company's cathodic protection system. There are two types of damage:

1. Damage to coatings due to too high a potential being impressed upon it; generally in excess of 2 v.
2. The corrosion of the pipeline as the result of cathodic interference current discharging from it. No current discharge can be tolerated from a well-coated high pressure pipeline. With old bare pipelines, it was not always possible to prevent all current discharge and in these cases a slight discharge, usually not more than 0.1 amp, may be tolerated.

There are four methods of correcting or preventing damage interference resulting from excessive voltage. The simplest way would be to move the route of a pipeline before installation; the second would be to remove cathodic protection stations that are the source of the trouble; the third would be to reduce the output of cathodic protection stations; and the fourth would be to move the interfered with pipeline. Insofar as current damage is concerned, it may be possible to bond between the protected and unportected pipeline and drain sufficient current back to prevent damage.

One method of handling cathodic protection interference problems before they occur is through the formation of a central electrolysis committee. This committee acts as a coordinating committee insofar as the installation of all cathodic protection stations are concerned. When one company indicates that it plans to install a rectifier station, this information is made available to the committee. The committee in turn disseminates it to any other companies that

would be directly concerned or related. This at least puts companies on notice that there is a possibility of cathodic interference.

SUMMARY AND CONCLUSIONS

Justification for the cost of a cathodic protection system for a pipeline must always result from the final resulting savings. The corrosion engineer must, to the best of his ability, determine the cost of corrosion, estimate what part of the loss would be prevented by application of cathodic protection, and determine the cost of cathodic protection. If the savings that can be gained are greater than the cost of cathodic protection, obviously the system should be installed.

Fig. 12 shows the cumulative costs of corrosion and corrosion control before and after installation of cathodic protection.[5] The facility consisted of 125 miles of 18-in. diameter natural gas transmission pipeline. The pipeline was installed originally in 1909 but when cathodic protection was finally applied, less than 1% of the original pipe remained. It had practically all been replaced because of corrosion.

Some 70% of the pipeline is bare and the resulting current requirements are quite high (in the magnitude of 3,000 amp. The total area of bare pipe under protection is about 2,000,000 sq ft and it is protected by 170 rectifier units. As would be expected, soil conditions vary widely; some sections in gumbo soil have a soil resistivity of less than 1,000 ohm cm, other sections have quite high resistivity, in excess of 10,000 ohm cm.

The majority of the cathodic protection installations were made eight years ago and in that time no replacements have been made. The cumulative savings for 20 yr resulting from the installation of cathodic protection are estimated to amount to $2,500,000, certainly a substantial sum.[5]

Fig. 13 illustrates a group of maintenance cost trend curves developed by the Montana Power Company for their natural gas distribution pipelines.[6] In 1936, a decision was made to cathodically protect the distribution system. By 1940, 80% was under protection and by 1958, 95% of the distribution piping was protected. The curve showing the 3-in. equivalent main installed is a cumulative total for only the piping installed after 1940. However, the maintenance cost for mains and services is the yearly total for the entire distribution system. The distribution cathodic protection cost is also the yearly total for the distribution system.[6]

The conclusion to be reached by a study of the data shows that even though the amount of distribution main installed since 1940 has increased enormously, the maintenance charges for the entire distribution system installed since 1934 declined until 1950. The gradual rise at that time can be attributed to the large amount of piping installed and the fact that some of the older mains would undoubtedly be due for replacement. The rising distribution cathodic protection costs are to be expected with the increase in total piping. Without application of cathodic protection, the maintenance cost curve would have continued upward and never declined.

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5 "Cathodic Protection as Applied to Underground Metal Structures," Federal Construction Council - Task Group T-27, May, 1958.

6 "A History of Cathodic Protection," by C. R. Davis, <u>Gas</u>, Vol. 139, March, 1960.

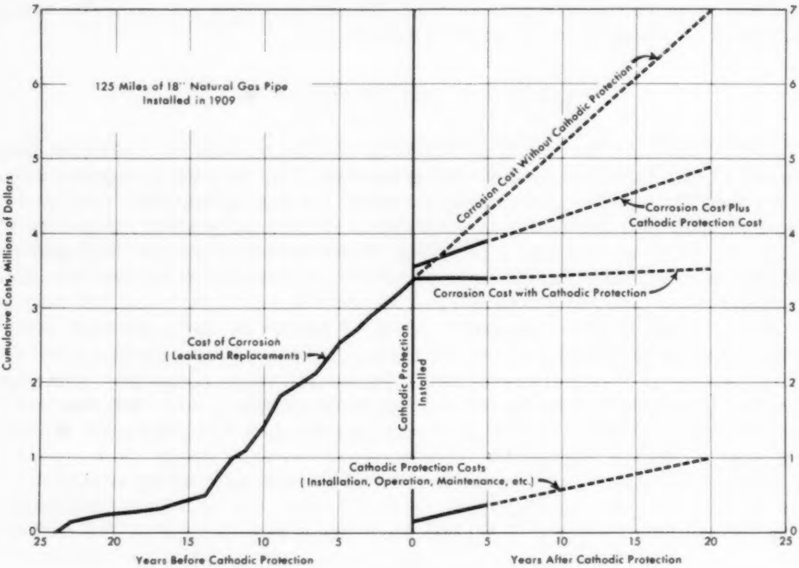

FIG. 12.—CUMULATIVE COSTS OF CORROSION AND CORROSION CONTROL BEFORE AND AFTER INSTALLATION OF CATHODIC PROTECTION

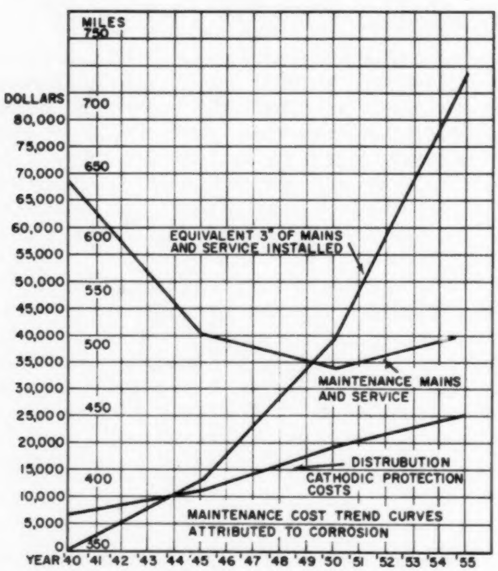

FIG. 13.—MAINTENANCE CURVES

In conclusion, the following major considerations should be kept in mind when considering designing cathodic protection systems:

1. Only those pipelines requiring cathodic protection should be protected. Experience, thorough field investigation and economics should determine whether or not a pipeline or a portion of a pipeline needs cathodic protection. The added cost should always be justified by the economic savings to be gained.
2. Insofar as applying extra thicknesses to pipe walls to allow for corrosion, a layer of steel is a very expensive and ineffective protective coating for a pipeline.
3. Cathodic protection has been effective in preventing and substantially reducing leakage in practically all instances where it has been applied, but to be effective it must be kept in operation continuously and maximum benefits are obtained only if it is installed before the pipeline has been seriously corroded.

Soil corrosion is characterized by many variations and as such is much more complex than atmospheric or water corrosion. This factor coupled with the large dollar loss resulting from underground corrosion justifies the use of the very best engineering talent and experience available when designing the necessary coatings and cathodic protection systems.

Journal of the

PIPELINE DIVISION

Proceedings of the American Society of Civil Engineers

DISCUSSION

NON-STEEL CYLINDER PRESTRESSED CONCRETE PIPES[a]

Closure by S. R. Hubbard

S. R. HUBBARD,[1] M. ASCE.—Hasker states that there is no reason why non-cylinder prestressed concrete pipes cannot be used for internal diameters less than 1 ft. Hasker is correct insofar as structural design is concerned. There is no theoretical limitation in the smallest or the largest size of prestressed pipe that may be made. The writer's approximate size limitations are based on economic considerations. These, and hence, the practical size range of prestressed pipes can vary greatly depending on the locality in which they are to be used.

It is technically possible to produce non-cylinder prestressed pipes which will withstand internal pressures greater than the 350 psi mentioned by the writer. Proof of this is the 33-in. diameter pipes in Austrailia mentioned by Hasker. These pipes were tested to 435 psi. The 350 psi mentioned in the writer's paper was intended to be an approximate practical working maximum. It is agreed that higher values may be obtained. The writer has conducted tests as high as 525 psi on 33-in. prestressed pipes without failure.

Hasker states that authorities frequently disagree on methods of combining the effect of internal and external loads. This is true, but it was thought that some mention of the subject should be made. The methods shown are intended only as a guide and not an attempt to cover the subject in detail.

The writer disagrees with Hasker's statement that earth loads are usually negligible. There are many instances, at least in the United States, where designs require considerable earth cover and the resulting loads are by no means negligible.

In acknowledgment of Hasker's remark pertaining to tensile stresses, it is agreed that they are of considerable importance in design and must be checked to be certain safe values are not exceeded.

Hasker is correct in stating that addition of direct and bending stresses does not yield a correct average value. However, direct addition of these stresses at the extreme fiber, that is at the inner or outer surface of the pipe, as indicated in the paper would appear to yield a correct value at these points.

Hasker emphasizes that the coating strengthens the pipe with regard to internal and external loads. This is true and it is generally regarded as an additional factor of safety. Attempts have been made to properly assess the structural value of the cover coat, but it is felt the assumptions necessary to perform computations for evaluating the coating effect do not warrant including it as anything other than an additional factor of safety.

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[a] October 1959, by S. R. Hubbard (Proc. Paper 2240).

[1] Vice-Pres., Cen-Vi-Ro Pipe Corp., Shafter, Calif.

Corrections.—The two equations at the bottom of page 35 should read as follows:

$$na_s^2\left[\frac{(c - 1)\, f_{sw} + \Delta\, E_s}{12\, t}\right] - a_s\left[(2 - e)\, f_{sw} - \Delta\, E_s\right] + 6\, D\, P_o = O$$

and

$$a_s = \frac{6t}{Q}\left[R \pm \left(R^2 - \frac{2\, P_o\, DQ}{t}\right)^{\frac{1}{2}}\right] \quad \ldots\ldots\ldots\ldots \quad (1)$$

PROCEEDINGS PAPERS

The technical papers published in the past year are identified by number below. Technical-division sponsorship is indicated by an abbreviation at the end of each Paper Number, the symbols referring to: Air Transport (AT), City Planning (CP), Construction (CO), Engineering Mechanics (EM), Highway (HW), Hydraulics (HY), Irrigation and Drainage (IR), Pipeline (PL), Power (PO), Sanitary Engineering (SA), Soil Mechanics and Foundations (SM), Structural (ST), Surveying and Mapping (SU), and Waterways and Harbors (WW), divisions. Papers sponsored by the Department of Conditions of Practice are identified by the symbols (PP). For titles and order coupons, refer to the appropriate issue of "Civil Engineering." Beginning with Volume 82 (January 1956) papers were published in Journals of the various Technical Divisions. To locate papers in the Journals, the symbols after the paper number are followed by a numeral designating the issue of a particular Journal in which the paper appeared. For example, Paper 2703 is identified as 2703(ST1) which indicates that the paper is contained in the first issue of the Journal of the Structural Division during 1961.

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OCTOBER: 2615(EM5), 2616(EM5), 2617(ST10), 2618(SM5), 2619(EM5), 2620(EM5), 2621(ST10), 2622(EM5), 2623(SM5), 2624(EM5), 2625(SM5), 2626(SM5), 2627(EM5), 2628(EM5), 2629(ST10), 2630(ST10), 2631(PO5)[c], 2632(EM5)[c], 2633(ST10), 2634(ST10), 2635(ST10)[c], 2636(SM5)[c].

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c. Discussion of several papers, grouped by divisions.

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